# B 3.6.1.5 Primary Containment Air Temperature

# BASES

BACKGROUND	Heat loads from the drywell, as well as piping and equipment in the primary containment, add energy to the primary containment airspace and raise airspace temperature. Coolers included in the unit design remove this energy and maintain an appropriate average temperature inside primary containment. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). This primary containment air temperature limit is an initial condition input for the Reference 1 safety analyses.
APPLICABLE SAFETY ANALYSES	Primary containment performance for the DBA is evaluated for a entire spectrum of break sizes for postulated loss of coolant accidents (LOCAs) inside containment (Ref. 1). Among the inputs to the design basis analysis is the initial primary containment average air temperature. Analyses assume an initial average primary containment air (and suppression pool) temperature of [95]°F. Maintaining the expected initial conditions ensures that safety analyses remain valid and ensures that the peak LOCA primary containment temperature does not exceed the maximum allowable temperature of 185°F (Ref. 1). Exceeding this design temperature may result in the degradation of the primary containment structure under accident loads. Equipment inside primary containment, and needed to mitigate the effects of a DBA, is designed to operate and be capable of operating under environmental conditions expected for the accident.
·	10 CFR 50.36(c)(2)(ii).
LCO	With an initial primary containment average air temperature less than or equal to the LCO temperature limit, the peak accident temperature is maintained below the primary containment design temperature. As a result, the ability of primary containment to perform its design function is ensured.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining primary

#### Primary Containment Air Temperature B 3.6.1.5

#### BASES

#### APPLICABILITY (continued)

containment average air temperature within the limit is not required in MODE 4 or 5.

#### ACTIONS

When primary containment average air temperature is not within the limit of the LCO, it must be restored within 8 hours. This Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 8 hour Completion Time is acceptable, considering the sensitivity of the analysis to variations in this parameter, and provides sufficient time to correct minor problems.

#### B.1 and B.2

A.1

If the primary containment average air temperature cannot be restored to within limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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 <u>SR 3.6.1.5.1</u> REQUIREMENTS

Verifying that the primary containment average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the primary containment analyses. In order to determine the primary containment average air temperature, an arithmetic average is calculated, using measurements taken at locations within the primary containment selected to provide a representative sample of the overall primary containment atmosphere.

The 24 hour Frequency of this SR is considered acceptable based on observed slow rates of temperature increase within primary containment as a result of environmental heat sources (due to large volume of the primary containment). 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 primary containment air temperature condition.

Primary Containment Air Temperature B 3.6.1.5

#### BASES

REFERENCES 1. FSAR, Section [6.2].

**BWR/6 STS** 

B 3.6.1.6 Low-Low Set (LLS) Valves

# BASES

BACKGROUND	The safety/relief valves (S/RVs) can actuate either in the relief mode, the safety mode, the Automatic Depressurization System mode, or the LLS mode. In the LLS mode (or power actuated mode of operation), a pneumatic diaphragm and stem assembly overcome the spring force and open the pilot valve. As in the safety mode, opening the pilot valve allows a differential pressure to develop across the main valve piston and thus opens the main valve. The main valve can stay open with valve inlet steam pressure as low as [0] psig. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure exceeds the safety mode pressure setpoints.
	[Six] of the S/RVs are equipped to provide the LLS function. The LLS logic causes the LLS valves to be opened at a lower pressure than the relief or safety mode pressure setpoints and stay open longer, such that reopening of more than one S/RV is prevented on subsequent actuations. Therefore, the LLS function prevents excessive short duration S/RV cycles with valve actuation at the relief setpoint.
	Each S/RV discharges steam through a discharge line and quencher to a location near the bottom of the suppression pool, which causes a load on the suppression pool wall. Actuation at lower reactor pressure results in a lower load.
APPLICABLE SAFETY ANALYSES	The LLS relief mode functions to ensure that the containment design basis of one S/RV operating on "subsequent actuations" is met (Ref. 1). In other words, multiple simultaneous openings of S/RVs (following the initial opening) and the corresponding higher loads, are avoided. The safety analysis demonstrates that the LLS functions to avoid the induced thrust loads on the S/RV discharge line resulting from "subsequent actuations" of the S/RV during Design Basis Accidents (DBAs). Furthermore, the LLS function justifies the primary containment analysis assumption that multiple simultaneous S/RV openings occur only on the initial actuation for DBAs. Even though [six] LLS S/RVs are specified, all [six] LLS S/RVs do not operate in any DBA analysis.
	LLS valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES	
LCO	[Six] LLS valves are required to be OPERABLE to satisfy the assumptions of the safety analysis (Ref. 2). 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	<u>A.1</u>
	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 and B.2
	If two or more LLS valves are inoperable or 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 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	<u>SR 3.6.1.6.1</u>
REQUIREMENTS	A manual actuation of each LLS valve is performed to verify that the valve and solenoids are functioning properly and that no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine control or bypass valve, by a change in the measured steam flow, or by any other method that is suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Adequate pressure at which this test is to be performed is $\geq$ [950] psig (the pressure recommended by the valve manufacturer). Also, adequate steam flow must be passing through the

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# SURVEILLANCE REQUIREMENTS (continued)

main turbine or turbine bypass valves to continue to control reactor pressure when the ADS valves divert steam flow upon opening. Adequate steam flow is represented by [at least 1.25 turbine bypass valves open, or total steam flow  $\ge 10^6$  lb/hr]. The [18] month Frequency was developed based on the S/RV tests required by the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 3). The Frequency of [18] months on a STAGGERED TEST BASIS ensures that each solenoid for each S/RV is alternately tested. Operating experience has shown these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

Since steam pressure is required in order to perform the Surveillance, however, and steam may not be available during a unit outage, the Surveillance may be performed during the shutdown prior to or the startup following a unit outage. Unit startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified by Reference 3 prior to valve installation. After adequate reactor steam dome pressure and flow are reached, 12 hours are allowed to prepare for and perform the test.

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

REFERENCES [	1.	GESSAR-II,	Appendix 3BA.8.	1
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- 2. FSAR, Section [5.5.17].
- 3. ASME, Boiler and Pressure Vessel Code, Section XI.

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B 3.6.1.7 Residual Heat Removal (RHR) Containment Spray System

# BASES

BACKGROUND	The primary containment is designed with a suppression pool so that, in the event of a loss of coolant accident (LOCA), steam released from the primary system is channeled through the suppression pool water and condensed without producing significant pressurization of the primary containment. The primary containment is designed so that with the pool initially at the minimum water volume and the worst single failure of the primary containment heat removal systems, suppression pool energy absorption combined with subsequent operator controlled pool cooling will prevent the primary containment pressure from exceeding its design value. However, the primary containment must also withstand a postulated bypass leakage pathway that allows the passage of steam from the drywell directly into the primary containment airspace, bypassing the suppression pool. The primary containment also must withstand a low energy steam release into the primary containment airspace. The RHR Containment Spray System is designed to mitigate the effects of bypass leakage, and low energy line breaks. There are two redundant, 100% capacity RHR containment spray subsystems. Each subsystem consists of a suction line from the suppression pool, an RHR pump, a heat exchanger, and three spray spargers inside the primary containment (outside of the drywell) above the refueling floor. Dispersion of the spray water is accomplished by 350 nozzles in each subsystem. The RHR containment spray mode will be automatically initiated, if required, following a LOCA, or it may be manually initiated according to emergency procedures.
APPLICABLE SAFETY ANALYSES	Reference 1 contains the results of analyses that predict the primary containment pressure response for a LOCA with the maximum allowable bypass leakage area
ANALIOLO	The equivalent flow path area for bypass leakage has been specified to
	be [0.9] ft <sup>2</sup> . The analysis demonstrates that with containment spray operation the primary containment pressure remains within design limits.
	The RHR Containment Spray System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES	
LCO	In the event of a Design Basis Accident (DBA), a minimum of one RHR containment spray subsystem is required to mitigate potential bypass leakage paths and maintain the primary containment peak pressure below design limits. To ensure that these requirements are met, two RHR containment spray subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR containment spray subsystem is OPERABLE when the pump, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. 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 RHR containment spray subsystems OPERABLE is not required in MODE 4 or 5.
ACTIONS	<u>A.1</u>
	With one RHR containment spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE RHR containment spray subsystem is adequate to perform the primary containment cooling function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment cooling capability. The 7 day Completion Time was chosen in light of the redundant RHR containment capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.
	<u>B.1</u>
	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 primary containment 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.
	<u>C.1 and C.2</u>
	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 LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and

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#### ACTIONS (continued)

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 <u>SR 3.6.1.7.1</u> REQUIREMENTS

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 can 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  $\geq$  [5650] gpm while operating in the suppression pool cooling mode with flow through the associated heat exchanger ensures that pump performance has not degraded during the cycle. It is tested in the pool cooling mode to demonstrate pump OPERABILITY without spraying down equipment in primary containment. Flow is a normal test of centrifugal pump performance required by the ASME Code, Section XI (Ref. 2). This test confirms one point on the pump design curve and is indicative of overall

#### SURVEILLANCE REQUIREMENTS (continued)

performance. Such inservice inspections confirm component OPEFABILITY, trend performance, and detect incipient failures by indicating abnormal performance. [The Frequency of this SR is in accordance with the Inservice Testing Program or 92 days.]

#### 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 3.3.6.3.6 overlaps this SR to provide complete testing of the safety function. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

#### <u>SR 3.6.1.7.4</u>

This Surveillance is performed every 10 years to verify that the spray nozzles are not obstructed and that flow will be provided when required. The 10 year Frequency is adequate to detect degradation in performance due to the passive nozzle design and its normally dry state and has been shown to be acceptable through operating experience.

- REFERENCES 1. IFSAR, Section [6.2.1.1.5].
  - 2. ASME, Boiler and Pressure Vessel Code, Section XI.

# B 3.6.1.8 Penetration Valve Leakage Control System (PVLCS)

# BASES

BACKGROUND	The PVLCS supplements the isolation function of primary containment isolation valves (PCIVs) in process lines that also penetrate the secondary containment. These penetrations are sealed by air from the PVLCS to prevent fission products leaking past the isolation valves and bypassing the secondary containment after a Design Basis Accident (DBA) loss of coolant accident (LOCA).
	The PVLCS consists of [two] independent, manually initiated subsystems, either of which is capable of preventing fission product leakage from the containment post LOCA. Each subsystem is comprised of an air compressor, an accumulator, an injection valve, and three injection headers with separate isolation valves. This system has additional headers, which serve the Main Steam Isolation Valve Leakage Control System and safety/relief valve (S/RV) actuator air accumulators.
	Each process line has two PCIVs and an additional manual isolation valve outside of the outboard PCIV. The two outboard valves are double disk gate valves. Each valve is provided sealing air from its electrically associated division of PVLCS to the area between the dual disk seats. The PVLCS is started manually.
APPLICABLE SAFETY ANALYSES	The analyses described in Reference 1 provide the evaluation of offsite dose consequences during accident conditions. During the first 25 minutes following an accident, the isolation valves on lines that penetrate primary containment and also penetrate secondary containment are assumed to leak fission products directly to the environment, without being processed by the Standby Gas Treatment System. The analyses take credit for manually initiating PVLCS after 25 minutes and do not assume any further secondary containment bypass leakage.
••••••••••••••••••••••••••••••••••••••	The PVLCS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	[Two] PVLCS subsystems must be OPERABLE such that in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. A PVLCS subsystem is OPERABLE when all necessary components are available to supply each associated dual seat isolation valve with sufficient air pressure to preclude containment

LCO (continued)	
	leakage when the containment atmosphere is at the maximum peak containment pressure, $P_a$ .
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the PVLCS is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.
ACTIONS	<u>A.1</u>
	With one PVLCS subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE PVLCS subsystem is adequate to perform the leakage control function. The 30 day Completion Time is based on the low probability of the occurrence of a LOCA, the amount of time available after the event for operator action to prevent exceeding this limit, the low probability of failure of the OPERABLE PVLCS subsystem, and the availability of the PCIVs.
	<u>B.1</u>
	With [two] PVLCS subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 7 days. The 7 day Completion Time is based on the low probability of the occurrence of a DBA LOCA, the availability of 25 minutes for operator action, and the availability of the PCIVs.
	C.1 and C.2
	If the inoperable PVLCS subsystem cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MOIDE 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.

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#### SURVEILLANCE REQUIREMENTS

#### <u>SR 3.6.1.8.1</u>

The minimum air supply necessary for PVLCS OPERABILITY varies with the system being supplied with compressed air from the PVLCS accumulators. Due to the support system function of PVLCS for S/RV actuator air, however, the specified minimum pressure of [101] psig is required, which provides sufficient air for [] S/RV actuations with the drywell pressure at 30 psig. This minimum air pressure alone is sufficient for PVLCS to support the OPERABILITY of these S/RV systems and is verified every 24 hours. The 24 hour Frequency is considered adequate in view of other indications available in the control room, such as alarms, to alert the operator to an abnormal PVLCS air pressure condition.

#### SR 3.6.1.8.2

A simulated system operation is performed every [18] months to ensure that the PVLCS will function throughout its operating sequence. This includes correct automatic positioning of valves once the system is initiated manually. Proper functioning of the compressor and valves is verified by this Surveillance. The [18] month Frequency was developed considering it is prudent that many Surveillances be performed only during a plant outage. Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES 1. FSAR, Section [15.6.5].

B 3.6.1.9 Main Steam Isolation Valve (MSIV) Leakage Control System (LCS)

# BASES BACKGROUND The MSIV LCS supplements the isolation function of the MSIVs by processing the fission products that could leak through the closed MSIVs after a Design Basis Accident (DBA) loss of coolant accident (LOCA). The MSIV LCS consists of two independent subsystems: an inboard subsystem, which is connected between the inboard and outboard MSIVs; and an outboard subsystem, which is connected immediately downstream of the outboard MSIVs. Each subsystem is capable of processing leakage from MSIVs following a DBA LOCA. Each subsystem consists of blowers (four blowers for the inboard subsystem and two blowers for the outboard subsystem), valves, piping, and heaters (for the inboard subsystem only). The four electric heaters in the inboard subsystem are provided to boil off any condensate prior to the gas mixture passing through the flow limiter. Each subsystem operates in two process modes: depressurization and bleedoff. The depressurization process reduces the steam line pressure to within the operating capability of equipment used for the bleedoff mode. During bleedoff (long term leakage control), the blowers maintain a negative pressure in the main steam lines (Ref. 1). This ensures that leakage through the closed MSIVs is collected by the MSIV LCS. In both process modes, the effluent is discharged to the auxiliary building, which encloses a volume served by the Standby Gas Treatment (SGT) System. The MSIV LCS is manually initiated approximately 20 minutes following a DBA LOCA (Ref. 2). APPLICABLE The MSIV LCS mitigates the consequences of a DBA LOCA by ensuring SAFETY that fission products that may leak from the closed MSIVs are diverted to ANALYSES the auxiliary building and ultimately filtered by the SGT System. The analyses in Reference 3 provide the evaluation of offsite dose consequences. The operation of the MSIV LCS prevents a release of untreated leakage for this type of event. The MSIV LCS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO	One MSIV LCS subsystem can provide the required processing of the MSIV leakage. To ensure that this capability is available, assuming worst case single failure, two MSIV LCS subsystems must be OPERABLE.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could lead to a fission product release to primary containment. Therefore, MSIV LCS OPERABILITY is required during these MODES. 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 MSIV LCS OPERABLE is not required in MODE 4 or 5 to ensure MSIV leakage is processed.
ACTIONS	A.1

#### ACTIONS

With one MSIV LCS subsystem inoperable, the inoperable MSIV LCS subsystem must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE MSIV LCS subsystem is adequate to perform the required leakage control function. However, the overall reliability is reduced because a single failure in the remaining subsystem could result in a total loss of MSIV leakage control function. The 30 day Completion Time is based on the redundant capability afforded by the remaining OPERABLE MSIV LCS subsystem and the low probability of a DBA LOCA occurring during this period.

#### **B.1**

With two MSIV LCS subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 7 days. The 7 day Completion Time is based on the low probability of the occurrence of a DBA LOCA.

#### C.1 and C.2

If the MSIV LCS subsystem cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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 3.6.1.9.1

Each MSIV LCS blower is operated for  $\geq$  [15] minutes to verify OPERABILITY. The 31 day Frequency was developed considering the known reliability of the LCS blower and controls, the two subsystem redundancy, and the low probability of a significant degradation of the MSIV LCS subsystem occurring between surveillances and has been shown to be acceptable through operating experience.

#### <u>SR 3.6.1.9.2</u>

The electrical continuity of each inboard MSIV LCS subsystem heater is verified by a resistance check, by verifying the rate of temperature increase meets specifications, or by verifying the current or wattage draw meets specifications. The 31 day Frequency is based on operating experience that has shown that these components usually pass this Surveillance when performed at this Frequency.

#### <u>SR 3.6.1.9.3</u>

A system functional test is performed to ensure that the MSIV LCS will operate through its operating sequence. This includes verifying that the automatic positioning of the valves and the operation of each interlock and timer are correct, that the blowers start and develop the required flow rate and the necessary vacuum, and the upstream heaters meet current or wattage draw requirements (if not used to verify electrical continuity in SR 3.6.1.9.2). The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

- REFERENCES 1. FSAR, Section [6.7].
  - 2. Regulatory Guide 1.96, Revision [1].
  - 3. FSAR, Section [15.6.5].

Suppression Pool Average Temperature B 3.6.2.1

#### B 3.6 CONTAINMENT SYSTEMS

#### B 3.6.2.1 Suppression Pool Average Temperature

#### BASES

#### BACKGROUND

The suppression pool is a concentric open container of water with a stainless steel liner that is located at the bottom of the primary containment. The suppression pool is designed to absorb the decay heat and sensible heat released during a reactor blowdown from safety/relief valve discharges or from a loss of coolant accident (LOCA). The suppression pool must also condense steam from the Reactor Core Isolation Cooling System turbine exhaust and provides the main emergency water supply source for the reactor vessel. The amount of energy that the pool can absorb as it condenses steam is dependent upon the initial average suppression pool temperature. The lower the initial pool temperature, the more heat it can absorb without heating up excessively. Since it is an open pool, its temperature will affect both primary containment pressure and average air temperature. Using conservative inputs and methods, the maximum calculated primary containment pressure during and following a Design Basis Accident (DBA) must remain below the primary containment design pressure of [15] psig. In addition, the maximum primary containment average air temperature must remain < [185]°F.

The technical concerns that lead to the development of suppression pool average temperature limits are as follows:

- a. Complete steam condensation [the original limit for the end of a LOCA blowdown was 170°F, based on the Bodega Bay and Humboldt Bay Tests],
- b. Primary containment peak pressure and temperature [the design pressure is [15] psig and design temperature is [185]°F],
- c. Condensation oscillation (CO) loads [a maximum allowable initial temperature of [100]°F ensures that CO loads do not exceed the Mark III CO load definition], and
- d. Chugging load [a maximum allowable initial temperature of [100]°F ensures that expected LOCA temperatures are within the range of Mark III tested conditions].

BA	SE	ES
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APPLICABLE SAFETY ANALYSES	The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses include initial suppression pool water volume and suppression pool temperature (Reference 1 for LOCAs and Reference 2 for the suppression pool temperature analyses required by Reference 3). An initial pool temperature of [95]°F is assumed for the Reference 1 and 2 analyses. Reactor shutdown at a pool temperature of [110]°F and vessel depressurization at a pool temperature of [120]°F are assumed for the Reference 2 analyses. The limit of [105]°F, at which testing is terminated, is not used in the safety analyses because DBAs are assumed to not initiate during plant testing.	
LCO	A limitation on the suppression pool average temperature is required to assure that the primary containment conditions assumed for the safety analysies are met. This limitation subsequently ensures that peak primary containment pressures and temperatures do not exceed maximum allowable values during a postulated DBA or any transient resulting in heatup of the suppression pool. The LCO requirements are as follows:	
	<ul> <li>Average temperature ≤ [95]°F [when any OPERABLE intermediate range monitor (IRM) channel is &gt; [25/40] divisions of full scale on Range 7] [with THERMAL POWER &gt; 1% RATED THERMAL POWER (RTP)], and no testing that adds heat to the suppression pool is being performed. This requirement ensures that licensing bases initial conditions are met.</li> </ul>	
	b. Average temperature ≤ [105]°F [when any OPERABLE IRM channel is > [25/40] divisions of full scale on Range 7] [with THERMAL POWER > 1% RTP] and testing that adds heat to the suppression pool is being performed. This requirement ensures that the plant has testing flexibility, and was selected to provide margin below the [110]°F limit at which reactor shutdown is required. When testing ends, temperature must be restored to ≤ [95]°F within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is > [95]°F is short enough not to cause a significant increase in plant risk.	
	c. Average temperature $\leq$ [110]°F [when all OPERABLE IRM channels are $\leq$ [25/40] divisions of full scale on Range 7] [with THERMAL POWER $\leq$ 1% RTP]. This requirement ensures that the plant will be	

BASES	
LCO (continued)	shut down at > [110]°F. The pool is designed to absorb decay heat and sensible heat but could be heated beyond design limits by the steam generated if the reactor is not shut down.
	[Note that [25/40] divisions of full scale on IRM Range 7 is a convenient measure of when the reactor is producing power essentially equivalent to 1% RTP]. At [this power level] [1% RTP], heat input is approximately equal to normal system heat losses.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause significant heatup of the suppression pool. 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 suppression pool average temperature within limits is not required in MODE 4 or 5.
ACTIONS	A.1 and A.2 With the suppression pool average temperature above the specified limit when not performing testing that adds heat to the suppression pool and
	when not performing testing that adds hear to the suppression poor and when above the specified power indication, the initial conditions exceed the conditions assumed for the Reference 1 and 3 analyses. However, primary containment cooling capability still exists, and the primary containment pressure suppression function will occur at temperatures well above that assumed for safety analyses. Therefore, continued operation is allowed for a limited time. The 24 hour Completion Time is adequate to allow the suppression pool temperature to be restored to below the limit. Additionally, when pool temperature is > [95]°F, increased monitoring of the pool temperature is required to ensure it remains $\leq$ [110]°F. The once per hour Completion Time is adequate based on past experience, which has shown that suppression pool temperature increases relatively slowly except when testing that adds heat to the pool is being performed. Furthermore, the once per hour Completion Time is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.
	<u>B.1</u>
	If the suppression pool average temperature cannot be restored to within

limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to [ $\leq$  [25/40] divisions of full scale

#### ACTIONS (continued)

on Range 7 for all OPERABLE IRM channels] [ $\leq$  1% RTP] within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power in an orderly manner and without challenging plant systems.

#### <u>C.1</u>

Suppression pool average temperature is allowed to be > [95]°F [with any OPEFIABLE IRM channel > [25/40] divisions of full scale on Range 7] [with THERMAL POWER > 1% RTP] when testing that adds heat to the suppression pool is being performed. However, if temperature is > [105]°F, the testing must be immediately suspended to preserve the pool's heat absorption capability. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

#### D.1 and D.2

Suppression pool average temperature >  $[110]^{\circ}F$  requires that the reactor be shut down immediately. This is accomplished by placing the reactor mode switch in the shutdown position. Further cooldown to MODIE 4 is required at normal cooldown rates (provided pool temperature remains  $\leq [120]^{\circ}F$ ). Additionally, when pool temperature is >  $[110]^{\circ}F$ , increased monitoring of pool temperature is required to ensure that it remains  $\leq [120]^{\circ}F$ . The once per 30 minute Completion Time is adequate, based on operating experience. Given the high pool temperature in this Condition, the monitoring Frequency is increased to twice that of Condition A. Furthermore, the 30 minute Completion Time is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

#### E.1 and E.2

If suppression pool average temperature cannot be maintained  $\leq$  [120]°F, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor pressure must be reduced to < [200] psig within 12 hours and the plant must be brought 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 without challenging plant systems.

ACTIONS (continued)		
SURVEILLANCE	<u>SR 3.6.2.1.1</u>	
	The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. Average temperature is determined by taking an arithmetic average of the OPERABLE suppression pool water temperature channels. The 24 hour Frequency has been shown to be acceptable based on operating experience. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently. The 5 minute Frequency during testing is justified by the rates at which testing will heat up the suppression pool, has been shown to be acceptable based on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequencies are further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.	
REFERENCES	1. FSAR, Section [6.2].	
	2. FSAR, Section [15.2].	
	3. NUREG-0783.	

#### B 3.6.2.2 Suppression Pool Water Level

#### BASES

BACKGROUND The suppression pool is a concentric open container of water with a stainless steel liner, which is located at the bottom of the primary containment. The suppression pool is designed to absorb the decay heat and sensible heat released during a reactor blowdown from safety/relief valve (S/RV) discharges or from a loss of coolant accident (LOCA). The suppression pool must also condense steam from the Reactor Core Isolation Cooling (RCIC) System turbine exhaust and provides the main emergency water supply source for the reactor vessel. The suppression pool volume ranges between [135,291] ft<sup>3</sup> at the low water level limit of [18 ft 4.5 inches] and [138,701] ft<sup>3</sup> at the high water level limit of [18 ft 9.75 inches].

If the suppression pool water level is too low, an insufficient amount of water would be available to adequately condense the steam from the S/RV quenchers, main vents, or RCIC turbine exhaust lines. Low suppression pool water level could also result in an inadequate emergency makeup water source to the Emergency Core Cooling System. The lower volume would also absorb less steam energy before heating up excessively. Therefore, a minimum suppression pool water level is specified.

If the suppression pool water level is too high, it could result in excessive clearing loads from S/RV discharges and excessive pool swell loads resulting from a Design Basis Accident (DBA) LOCA. An inadvertent upper pool dump could also overflow the weir wall into the drywell. Therefore, a maximum pool water level is specified. This LCO specifies an acceptable range to prevent the suppression pool water level from being either too high or too low.

APPLICABLE SAFETY ANALYSES

Initial suppression pool water level affects suppression pool temperature response calculations, calculated drywell pressure during vent clearing for a DBA, calculated pool swell loads for a DBA LOCA, and calculated loads due to S/RV discharges. Suppression pool water level must be maintained within the limits specified so that the safety analysis of Reference 1 remains valid.

Suppression pool water level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

BASES	
LCO	A limit that suppression pool water level be $\geq$ [18 ft 4.5 inches] and $\leq$ [18 ft 9.75 inches] is required to ensure that the primary containment conditions assumed for the safety analysis are met. Either the high or low water level limits were used in the safety analysis, depending upon which is conservative for a particular calculation.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause significant loads on the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced because of the pressure and temperature limitations in these MODES. The requirements for maintaining suppression pool water level within limits in MODE 4 or 5 is addressed in LCO 3.5.2, "ECCS-Shutdown."
ACTIONS	A.1 With suppression pool water level outside the limits, the conditions assumed for the safety analysis are not met. If water level is below the minimum level, the pressure suppression function still exists as long as main vents are covered, RCIC turbine exhausts are covered, and S/RV quenchers are covered. If suppression pool water level is above the maximum level, protection against overpressurization still exists due to the margin in the peak containment pressure analysis or as long as the drywell sprays are OPERABLE. Prompt action to restore the suppression pool water level to within the normal range is prudent, however, to retain the margin to weir wall overflow from an inadvertent upper pool dump and reduce the risks of increased pool swell and dynamic loading. Therefore, continued operation for a limited time is allowed. The 2 hour Completion Time is sufficient to restore suppression pool water level to within specified limits. Also, it takes into account the low probability of an event impacting the suppression pool water level occurring during this interval. B.1 and B.2 If suppression pool water level cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in
	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 the required plant conditions from full power conditions in an orderly manner and without challenging plant

. systems.

SURVEILLANCE REQUIREMENTS	<u>SR 3.6.2.2.1</u>
	required limits are satisfied. The 24 hour Frequency of this SR was developed considering operating experience related to trending variations in suppression pool water level and water level instrument drift during the applicable MODES and to assessing the proximity to the specified LCO level limits. 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 suppression pool water level condition.
REFERENCES	1. FSAR, Section [6.2].

B 3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

#### BASES

BACKGROUND Following a Design Basis Accident (DBA), the RHR Suppression Pool Cooling System removes heat from the suppression pool. The suppression pool is designed to absorb the sudden input of heat from the primary system. In the long term, the pool continues to absorb residual heat generated by fuel in the reactor core. Some means must be provided to remove heat from the suppression pool so that the temperature inside the primary containment remains within design limits. This function is provided by two redundant RHR suppression pool cooling subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

> Each RHR subsystem contains a pump and two heat exchangers in series and is manually initiated and independently controlled. The two RHR subsystems perform the suppression pool cooling function by circulating water from the suppression pool through the RHR heat exchangers and returning it to the suppression pool. RHR service water, circulating through the tube side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the external heat sink.

> The heat removal capability of one RHR subsystem is sufficient to meet the overall DBA pool cooling requirement to limit peak temperature to [185]°F for loss of coolant accidents (LOCAs) and transient events such as a turbine trip or a stuck open safety/relief valve (S/RV). S/RV leakage and Reactor Core Isolation Cooling System testing increase suppression pool temperature more slowly. The RHR Suppression Pool Cooling System is also used to lower the suppression pool water bulk temperature following such events.

APPLICABLE SAFETY ANALYSES Reference 1 contains the results of analyses used to predict primary containment pressure and temperature following large and small break LOCAs. The intent of the analyses is to demonstrate that the heat removal capacity of the RHR Suppression Pool Cooling System is adequate to maintain the primary containment conditions within design limits. The suppression pool temperature is calculated to remain below the design limit.

The RHR Suppression Pool Cooling System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES	
LCO	During a DBA, a minimum of one RHR suppression pool cooling subsystem is required to maintain the primary containment peak pressure and temperature below the design limits (Ref. 1). To ensure that these requirements are met, two RHR suppression pool cooling subsystems must be OPERABLE with power from two safety related independent power supplies. Therefore, in the event of an accident, at least one subsystem is OPERABLE, assuming the worst case single active failure. An RHR suppression pool cooling subsystem is OPERABLE when the pump, two heat exchangers, and associated piping, valves, instrumentation, and controls are OPERABLE.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment and cause a heatup and pressurization of primary containment. 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, the RHR Suppression Pool Cooling System is not required to be OPERABLE in MODE 4 or 5.
ACTIONS	<u>A.1</u>
	With one RHR suppression pool cooling subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining RHR suppression pool cooling subsystem is adequate to perform the primary containment cooling function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment cooling capability. The 7 day Completion Time is acceptable in light of the redundant RHR suppression pool cooling capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.
	<u>B.1</u>
	With two RHR suppression pool cooling subsystems inoperable, one subsystem must be restored to OPERABLE status within 8 hours. In this condition, there is a substantial loss of the primary containment pressure and temperature 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 the potential avoidance of a plant shutdown transient that could result in the need for the RHR suppression pool cooling subsystems to operate.

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ACTIONS (continued)

#### C.1 and C.2

If the Required Action and required Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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 <u>SR 3.6.2.3.1</u> REQUIREMENTS

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.

#### SR 3.6.2.3.2

Verifying each RHR pump develops a flow rate  $\geq$  [7450] gpm, while operating in the suppression pool cooling mode with flow through the associated heat exchanger at least every 92 days, ensures that pump performance has not degraded during the cycle. Flow is a normal test of centrifugal pump performance required by ASME Section XI (Ref. 2). 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

SURVEILLANCE REQUIREMENTS (continued)

failures by indicating abnormal performance. The Frequency of this SR is [in accordance with the Inservice Testing Program or 92 days].

- REFERENCES 1. FSAR, Section [6.2].
  - 2. ASME, Boiler and Pressure Vessel Code, Section XI.

# B 3.6.2.4 Suppression Pool Makeup (SPMU) System

#### BASES

#### BACKGROUND

The function of the SPMU System is to transfer water from the upper containment pool to the suppression pool after a loss of coolant accident (LOCA). For a LOCA, with Emergency Core Cooling System injection from the suppression pool, a large volume of water can be held up in the drywell behind the weir wall. This holdup can significantly lower suppression pool water level. The water transfer from the SPMU System ensures a post LOCA suppression pool vent coverage of  $\geq$  2 ft above the top of the top row vents so that long term steam condensation is maintained. The additional makeup water is used as part of the long term suppression pool heat sink. The post LOCA delayed transfer of this water to the suppression pool provides an initially low vent submergence, which results in lower drywell pressure loading and lower pool dynamic loading during a Design Basis Accident (DBA) LOCA as compared to higher vent submergence. The sizing of the residual heat removal heat exchanger takes credit for the additional SPMU System water mass in the calculation of the post LOCA peak containment pressure and suppression pool temperature.

The required water dump volume from the upper containment pool is equal to the difference between the total post LOCA drawdown volume and the assumed volume loss from the suppression pool. The total drawdown volume is the volume of suppression pool water that can be entrapped outside of the suppression pool following a LOCA. The post LOCA entrapment volumes causing suppression pool level drawdown include:

- a. The free volume inside and below the top of the drywell weir wall,
- b. The added volume required to fill the reactor pressure vessel from a condition of normal power operation to a post accident complete fill of the vessel, including the top dome,
- c. The volume in the steam lines out to the inboard main steam isolation valve (MSIV) on three lines and out to the outboard MSIV on one line, and
- d. Allowances for primary containment spray holdup on equipment and structural surfaces.

#### BACKGROUND (continued)

Although the minimum freeboard distance above the suppression pool high water level limit of LCO 3.6.2.2, "Suppression Pool Water Level," to the top of the weir wall is adequate to preclude flooding of the drywell, a LOCA permissive signal is used to prevent an erroneous suppression pool level signal from causing pool dump. In addition, the SPMU System mode switch may be keylocked in the "OFF" position to ensure that inadvertent dump will not occur. Inadvertent actuation of the SPMU System during MODE 4 or 5 could create a radiation hazard to plant personnel due to a loss of shield water from the upper pool if irradiated fuel were in an elevated position.

APPLICABLE SAFETY ANALYSES ANA

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

LCO

During a DBA, a minimum of one SPMU subsystem is required to maintain peak suppression pool water temperature below the design limits (Ref. 1). To ensure that these requirements are met, two SPMU subsystems must be OPERABLE with power from two independent safety related power supplies. Therefore, in the event of an accident, at least one subsystem is OPERABLE, assuming the worst case single active failure. The SPMU System is OPERABLE when the upper

DAOLO	
LCO (continued)	
	containment pool water temperature is $\leq [125]^\circ$ F, the water level is $\geq [23 \text{ ft } 3 \text{ inches}]$ , gates are in the stored condition, the piping is intact, and the system valves are OPERABLE. The above temperature and water level conditions correspond to an SPMU System available dump volume of $\geq [36,380]$ ft <sup>3</sup> .
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause heatup and pressurization of the primary containment. 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 SPMU System OPERABLE is not required in MODE 4 or 5.
ACTIONS	<u>A.1</u>
	When upper containment pool water level is < [23 ft 3 inches], the volume is inadequate to ensure that the suppression pool heat sink capability matches the safety analysis assumptions. A sufficient quantity of water is necessary to ensure long term energy sink capabilities of the suppression pool and maintain water coverage over the uppermost drywell vents. Loss of water volume has a relatively large impact on heat sink capability. Therefore, the upper containment pool water level must be restored to within limit within 4 hours. The 4 hour Completion Time is sufficient to provide makeup water to the upper containment pool to restore level within specified limit. Also, it takes into account the low probability of an event occurring that would require the SPMU System.
	<u>B.1</u>
	When upper containment pool water temperature is > [125]°F, the heat absorption capacity is inadequate to ensure that the suppression pool heat sink capability matches the safety analysis assumptions. Increased temperature has a relatively smaller impact on heat sink capability. Therefore, the upper containment pool water temperature must be restored to within limit within 24 hours. The 24 hour Completion Time is sufficient to restore the upper containment pool to within the specified temperature limit. It also takes into account the low probability of an event occurring that would require the SPMU System.
	<u>C.1</u>
	With one SPMU subsystem inoperable for reasons other than Condition A or B, the inoperable subsystem must be restored to

#### **ACTIONS** (continued)

OPERABLE status within 7 days. The 7 day Completion Time is acceptable in light of the redundant SPMU System capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

#### D.1 and D.2

If any Required Action and required Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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 3.6.2.4.1

The upper containment pool water level is regularly monitored to ensure that the required limits are satisfied. The 24 hour Frequency of this SR was developed, considering operating experience related to upper containment pool water level variations and water level instrument drift during the applicable MODES and considering 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 upper containment pool water level condition.

#### SR 3.6.2.4.2

The upper containment pool water temperature is regularly monitored to ensure that the required limit is satisfied. The 24 hour Frequency was developed, based on operating experience related to upper containment pool temperature variations during the applicable MODES.

#### SR 3.6.2.4.3

Verifying the correct alignment for manual, power operated, and automatic valves in the SPMU System 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 valves are verified to be in the correct position prior to being locked, sealed, or secured. This SR does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of

# SURVEILLANCE REQUIREMENTS (continued)

potentially 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 and because improper valve position would affect only a single subsystem. This Frequency has been shown to be acceptable through operating experience.

#### [<u>SR 3.6.2.4.4</u>

The upper containment pool has two gates used to separate the pool into distinct sections to facilitate fuel transfer and maintenance during refueling operations and two additional gates in the separator pool weir wall extension, which, when installed, limit personnel exposure and ensure adequate water submergence of the separator when the separator is stored in the pool. The SPMU System dump line penetrations are located in the steam separator storage section of the suppression pool, the gates must be removed (or placed in their stored position) to allow communication between the various pool sections. The 31 day Frequency is appropriate because the gates are moved under procedural control and only the infrequent movement of these gates is required in MODES 1, 2, and 3. ]

#### SR 3.6.2.4.5

This SR requires a verification that each SPMU subsystem automatic valve actuates to its correct position on receipt of an actual or simulated automatic initiation signal. This includes verification of the correct automatic positioning of the valves and of the operation of each interlock and timer. As noted, actual makeup to the suppression pool may be excluded. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.4.6 overlaps this SR to provide complete testing of the safety function. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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REFERENCES 1. FSAR, Section [6.2].

2. FSAR, Chapter [15].

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Primary Containment Hydrogen Recombiners B 3.6.3.1

#### B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 Primary Containment Hydrogen Recombiners

#### BASES

# BACKGROUND The primary containment hydrogen recombiner eliminates the potential breach of primary containment due to a hydrogen oxygen reaction and is part of combustible gas control required by 10 CFR 50.44, "Standards for Combustible Gas Control in Light-Water-Cooled Reactors" (Ref. 1), and GDC 41, "Containment Atmosphere Cleanup" (Ref. 2). The primary containment hydrogen recombiner is required to reduce the hydrogen concentration in the primary containment following a loss of coolant accident (LOCA). The primary containment hydrogen recombining hydrogen and oxygen to form water vapor. The vapor remains in the primary containment, thus eliminating any discharge to the environment. The primary containment hydrogen recombiner is manually initiated, since flammability limits would not be reached until several days after a Design Basis Accident (DBA).

Two 100% capacity independent primary containment hydrogen recombiner subsystems are provided. Each consists of controls located in the control room, a power supply, and a recombiner located in primary containment. The recombiners have no moving parts. Recombination is accomplished by heating a hydrogen air mixture to > [1150]°F. The resulting water vapor and discharge gases are cooled prior to discharge from the unit. Air flows through the unit at [100] cfm, with natural circulation in the unit providing the motive force. A single recombiner is capable of maintaining the hydrogen concentration in primary containment below the 4.0 volume percent (v/o) flammability limit. Two recombiners are provided to meet the requirement for redundancy and independence. Each recombiner is powered from a separate Engineered Safety Feature bus and is provided with separate power panel and control panel.

Emergency operating procedures direct that the hydrogen concentration in primary containment be monitored following a DBA and that the primary containment hydrogen recombiner be manually activated to prevent the primary containment atmosphere from reaching a bulk hydrogen concentration of 4.0 v/o.
BASES	
APPLICABLE SAFETY ANALYSES	The primary containment hydrogen recombiner provides the capability of controlling the bulk hydrogen concentration in primary containment to less than the lower flammable concentration of 4.0 v/o following a DBA. This control would prevent a primary containment wide hydrogen burn, thus ensuring that pressure and temperature conditions assumed in the analysis are not exceeded. The limiting DBA relative to hydrogen generation is a LOCA.
	Hydrogen may accumulate in primary containment following a LOCA as a result of either:
	<ul> <li>A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant or</li> </ul>
	b. Radiolytic decomposition of water in the Reactor Coolant System.
	To evaluate the potential for hydrogen accumulation in primary containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Assumptions recommended by Reference 3 are used to maximize the amount of hydrogen calculated.
	The calculation confirms that when the mitigating systems are actuated in accordance with plant procedures, the peak hydrogen concentration in the prirnary containment remains < 4 v/o (Ref. 4).
	The primary containment hydrogen recombiners satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Two primary containment hydrogen recombiners must be OPERABLE. This ensures operation of at least one primary containment hydrogen recombiner in the event of a worst case single active failure.
	Operation with at least one primary containment hydrogen recombiner subsystem ensures that the post LOCA hydrogen concentration can be prevented from exceeding the flammability limit.
APPLICABILITY	In MODES 1 and 2, the two primary containment hydrogen recombiners are required to control the hydrogen concentration within primary containment below its flammability limit of 4.0 v/o following a LOCA, assuming a worst case single failure.
	In MODE 3, both the hydrogen production rate and the total hydrogen production after a LOCA would be less than that calculated for the DBA

# APPLICABILITY (continued)

A.1

LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the primary containment hydrogen recombiner is low. Therefore, the primary containment hydrogen recombiner is not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are low due to the pressure and temperature limitations in these MODES. Therefore, the primary containment hydrogen recombiner is not required in these MODES.

#### ACTIONS

With one primary containment hydrogen recombiner inoperable, the inoperable primary containment hydrogen recombiner must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE primary containment recombiner is adequate to perform the hydrogen control function. However, the overall reliability is reduced because a single failure in the OPERABLE recombiner could result in reduced hydrogen control capability. The 30 day Completion Time is based on the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the amount of time available after the event for operator action to prevent hydrogen accumulation exceeding this limit, and the low probability of failure of the OPERABLE primary containment hydrogen recombiner.

Required Action A.1 has been modified by a Note stating that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one recombiner is inoperable. This allowance is provided because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the low probability of the failure of the OPERABLE recombiner, and the amount of time available after a postulated LOCA for operator action to prevent exceeding the flammability limit.

#### <u>B.1 and B.2</u>

#### - REVIEWER'S NOTE -

This Condition is only allowed for units with an alternate hydrogen control system acceptable to the technical staff.

#### ACTIONS (continued)

With two primary containment hydrogen recombiners inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by [one division of the hydrogen ignitors]. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist.

#### - REVIEWER'S NOTE -

The following is to be used if a non-Technical Specification alternate hydrogen control function is used to justify this Condition: In addition, the alternate hydrogen control system capability must be verified once per 12 hours thereafter to ensure its continued availability.

[Both] the [initial] verification [and all subsequent verifications] may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two hydrogen recombiners inoperable for up to 7 days. Seven days is a reasonable time to allow two hydrogen recombiners to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in the amounts capable of exceeding the flammability limit.

#### <u>C.1</u>

If any Required Action and required Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

#### SURVEILLANCE <u>SR</u> REQUIREMENTS

#### <u>SR 3.6.3.1.1</u>

Performance of a system functional test for each primary containment hydrogen recombiner ensures that the recombiners are OPERABLE and can attain and sustain the temperature necessary for hydrogen recombination. In particular, this SR requires verification that the

# SURVEILLANCE REQUIREMENTS (continued)

minimum heater sheath temperature increases to  $\geq$  [1200]°F in

 $\leq$  [5] hours and that it is maintained > [1150] and < [1300]°F for

 $\geq$  [4] hours to check the capability of the recombiner to properly function (and that significant heater elements are not burned out).

Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

#### <u>SR 3.6.3.1.2</u>

This SR ensures that there are no physical problems that could affect primary containment hydrogen recombiner operation. Since the recombiners are mechanically passive, they are not subject to mechanical failure. The only credible failures involve loss of power, blockage of the internal flow path, missile impact, etc. A visual inspection is sufficient to determine abnormal conditions that could cause such failures.

Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

#### SR 3.6.3.1.3

This SR requires performance of a resistance to ground test of each heater phase to ensure that there are no detectable grounds in any heater phase. This is accomplished by verifying that the resistance to ground for any heater phase is  $\geq [10,000]$  ohms.

Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

- REFERENCES 1. 10 CFR 50.44.
  - 2. 10 CFR 50, Appendix A, GDC 41.
  - 3. Regulatory Guide 1.7, Revision [1].

#### Primary Containment Hydrogen Recombiners B 3.6.3.1

BASES

\_\_\_\_1

REFERENCES (continued)

4. FSAR, Section [6.2.5].

#### B 3.6 CONTAINMENT SYSTEMS

#### B 3.6.3.2 Primary Containment and Drywell Hydrogen Ignitors

#### BASES

#### BACKGROUND

The primary containment and drywell hydrogen ignitors are a part of the combustible gas control required by 10 CFR 50.44 (Ref. 1) and GDC 41, "Containment Atmosphere Cleanup" (Ref. 2), to reduce the hydrogen concentration in the primary containment following a degraded core accident. The hydrogen ignitors ensure the combustion of hydrogen in a manner such that containment overpressure failure is prevented as a result of a postulated degraded core accident.

10 CFR 50.44 (Ref. 1) requires boiling water reactor units with Mark III containments to install suitable hydrogen control systems. The hydrogen ignitors are installed to accommodate an amount of hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water. This requirement was placed on reactor units with Mark III containments because they were not designed for inerting and because of their low design pressure. Calculations indicate that if hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water were to collect in primary containment, the resulting hydrogen concentration would be far above the lower flammability limit such that, without the hydrogen ignitors, if the hydrogen were ignited from a random ignition source, the resulting hydrogen burn would seriously challenge the primary containment.

The hydrogen ignitors are based on the concept of controlled ignition using thermal ignitors designed to be capable of functioning in a post accident environment, seismically supported and capable of actuation from the control room. Ignitors are distributed throughout the [32] regions of the drywell and primary containment in which hydrogen could be released or to which it could flow in significant quantities. The hydrogen ignitors are arranged in two independent divisions such that each containment region has two ignitors, one from each division, controlled and powered redundantly so that ignition would occur in each region even if one division failed to energize.

When the hydrogen ignitors are energized they heat up to a surface temperature  $\geq [1700]^{\circ}F$ . At this temperature, they ignite the hydrogen gas that is present in the airspace in the vicinity of the ignitor. The hydrogen ignitors depend on the dispersed location of the ignitors so that local pockets of hydrogen at increased concentrations would burn before reaching a hydrogen concentration significantly higher than the lower flammability limit. Hydrogen ignition in the vicinity of the ignitors is

BACKGROUND (continued)	
	assumed to occur when the local hydrogen concentration reaches [8.0] volume percent (v/o) and results in [85]% of the hydrogen present being consumed.
APPLICABLE SAFETY ANALYSES	The hydrogen ignitors cause hydrogen in containment to burn in a controlled manner as it accumulates following a degraded core accident (Ref. 3). Burning occurs at the lower flammability concentration, where the resulting temperatures and pressures are relatively benign. Without the system, hydrogen could build up to higher concentrations that could result in a violent reaction if ignited by a random ignition source after such a buildup.
	The hydrogen ignitors are not included for mitigation of a Design Basis Accident (DBA) because an amount of hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water is far in excess of the hydrogen calculated for the limiting DBA loss of coolant accident (LOCA). The hydrogen concentration resulting from a DBA can be maintained less than the flammability limit using the hydrogen recombiners. However, the hydrogen ignitors have been shown by probabilistic risk analysis to be a significant contributor to limiting the severity of accident sequences that are commonly found to dominate risk for units with Mark III containment.
	The hydrogen ignitors satisfy Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	Two divisions of primary containment and drywell hydrogen ignitors must be OPERABLE, each with more than 90% of the ignitors OPERABLE.
	This ensures operation of at least one ignitor division, with adequate coverage of the primary containment and drywell, in the event of a worst case single active failure. This will ensure that the hydrogen concentration remains near 4.0 v/o.
APPLICABILITY	In MODES 1 and 2, the hydrogen ignitor is required to control hydrogen concentration to near the flammability limit of 4.0 v/o following a degraded core event that would generate hydrogen in amounts equivalent to a metal water reaction of 75% of the core cladding. The control of hydrogen concentration prevents overpressurization of the primary containment. The event that could generate hydrogen in quantities sufficiently high enough to exceed the flammability limit is limited to MODES 1 and 2.

#### APPLICABILITY (continued)

In MODE 3, both the hydrogen production rate and the total hydrogen produced after a degraded core accident would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the hydrogen ignitor is low. Therefore, the hydrogen ignitor is not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a degraded core accident are reduced due to the pressure and temperature limitations. Therefore, the hydrogen ignitors are not required to be OPERABLE in MODES 4 and 5 to control hydrogen.

# ACTIONS

A.1

With one hydrogen ignitor division inoperable, the inoperable division must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE hydrogen ignitor division is adequate to perform the hydrogen burn function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced hydrogen control capability. The 30 day Completion Time is based on the low probability of the occurrence of a degraded core event that would generate hydrogen in amounts equivalent to a metal water reaction of 75% of the core cladding, the amount of time available after the event for operator action to prevent hydrogen accumulation from exceeding the flammability limit, and the low probability of failure of the OPERABLE hydrogen ignitor division.

Required Action A.1 has been modified by a Note indicating the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one hydrogen ignitor division is inoperable or when one or more areas with adjacent ignitors are inoperable. The allowance is provided because of the low probability of the occurrence of an event that would generate hydrogen in amounts capable of exceeding the flammability limit, the low probability of the failure of both hydrogen ignitor divisions or adjacent ignitors, and the amount of time available after the event for operator action to prevent exceeding the flammability limit.

#### B.1 and B.2

With two primary containment and drywell ignitor divisions inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by one hydrogen recombiner and one drywell purge subsystem. The 1 hour Completion Time allows a

# ACTIONS (continued)

	reasonable period of time to verify that a loss of hydrogen control function does not exist. The verification may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control capabilities. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control capabilities. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two ignitor divisions inoperable for up to 7 days. Seven days is a reasonable time to allow two ignitor divisions to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in the arnounts capable of exceeding the flammability limit.
	<u>C.1</u>
	If any Required Action and required Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.
SURVEILLANCE RECHIBEMENTS	SR 3.6.3.2.1 and SR 3.6.3.2.2
	These SRs verify that there are no physical problems that could affect the ignitor operation. Since the ignitors are mechanically passive, they are not subject to mechanical failure. The only credible failures are loss of power or burnout. The verification that each required ignitor is energized is performed by circuit current versus voltage measurement.
	The Frequency of 184 days has been shown to be acceptable through operating experience because of the low failure occurrence, and provides assurance that hydrogen burn capability exists between the more rigorous 18 month Surveillances. Operating experience has shown these components usually pass the Surveillance when performed at a 184 day Frequency. Additionally, these surveillances must be performed every 92 days if four or more ignitors in any division are inoperable. The 92 day Frequency was chosen, recognizing that the failure occurrence is higher than normal. Thus, decreasing the Frequency from 184 days to 92 days is a prudent measure, since only two more inoperable ignitors (for a total of six) will result in an inoperable ignitor division. SR 3.6.3.2.2 is modified

#### SURVEILLANCE REQUIREMENTS (continued)

performed until 92 days after four or more ignitors in the division are discovered to be inoperable.

[ SR 3.6.3.2.3 and SR 3.6.3.2.4

These functional tests are performed every 18 months to verify system OPERABILITY. The current draw to develop a surface temperature of  $\ge 1700^{\circ}$ F is verified for ignitors in inaccessible areas, e.g., in a high radiation area. Additionally, the surface temperature of each accessible ignitor is measured to be  $\ge 1700^{\circ}$ F to demonstrate that a temperature sufficient for ignition is achieved. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. 1

REFERENCES 1. 10 CFR 50.44.

2. 10 CFR 50, Appendix A, GDC 41.

3. FSAR, Section [6.2.5].

#### B 3.6 CONTAINMENT SYSTEMS

#### B 3.6.3.3 [Drywell Purge System]

#### BASES

# BACKGROUND

The [Drywell Purge System] ensures a uniformly mixed post accident containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration.

The [Drywell Purge System] is an Engineered Safety Feature and is designed to operate following a loss of coolant accident (LOCA) in post accident environments without loss of function. The system has two independent subsystems, each consisting of a compressor and associated valves, controls, and piping. Each subsystem is sized to pump [500] scfm. Each subsystem is powered from a separate emergency power supply. Since each subsystem can provide 100% of the mixing requirements, the system will provide its design function with a worst case single active failure.

Following a LOCA, the drywell is immediately pressurized due to the release of steam into the drywell environment. This pressure is relieved by the lowering of the water level within the weir wall, clearing the drywell vents and allowing the mixture of steam and noncondensibles to flow into the primary containment through the suppression pool, removing much of the heat from the steam. The remaining steam in the drywell begins to condense as steam flow from the reactor pressure vessel ceases, the drywell pressure falls rapidly. Both drywell purge compressors start automatically 30 seconds after a LOCA signal is received from the Emergency Core Cooling System instrumentation, but only when drywell pressure has decreased to within approximately [0.087] psi above primary containment pressure. This ensures the blowdown from the drywell to the primary containment is complete. The drywell purge compressors force air from the primary containment into the drywell. Drywell pressure increases until the water level between the weir wall and the drywell is forced down to the first row of suppression pool vents forcing drywell atmosphere back into containment and mixing with containment atmosphere to dilute the hydrogen. While drywell purge continues following the LOCA, hydrogen continues to be produced. Eventually, the 4.0 v/o limit is again approached and the hydrogen recombiners are manually placed in operation.

# [Drywell Purge System] B 3.6.3.3

BASES	
APPLICABLE SAFETY ANALYSES	The [Drywell Purge System] provides the capability for reducing the drywell hydrogen concentration to approximately the bulk average primary containment concentration following a Design Basis Accident (DBA). The limiting DBA relative to hydrogen generation is a LOCA.
	Hydrogen may accumulate in primary containment following a LOCA as a result of:
	a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant and
	<ul> <li>Fladiolytic decomposition of water in the Reactor Coolant System and drywell sump.</li> </ul>
	To evaluate the potential for hydrogen accumulation in primary containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Reference 1 are used to maximize the amount of hydrogen calculated.
	[Based on a conservative assumption used to calculate the hydrogen concentration versus time after a LOCA, the hydrogen concentration in the primary containment would reach [3.5 v/o about 6 days] after the LOCA and [4.0 v/o about 2 days] later if no hydrogen mixing and recombiner were functioning (Ref. 2).]
	The [Drywell Purge System] satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Two [drywell purge] subsystems must be OPERABLE to ensure operation of at least one primary containment [drywell purge] subsystem in the event of a worst case single active failure. Operation with at least one OPERABLE [drywell purge] subsystem provides the capability of controlling the hydrogen concentration in the drywell without exceeding the flammability limit.
APPLICABILITY	In MCDES 1 and 2, the two [drywell purge] subsystems ensure the capability to prevent localized hydrogen concentrations above the flammability limit of 4.0 v/o in the drywell, assuming a worst case single active failure.
	In MODE 3, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of
••••••••••••••••••••••••••••••••••••••	

#### APPLICABILITY (continued)

A.1

an accident requiring the [Drywell Purge System] is low. Therefore, the [Drywell Purge System] is not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, the [Drywell Purge System] is not required in these MODES.

#### ACTIONS

With one [drywell purge] subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE subsystem is adequate to perform the drywell purge function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced drywell purge capability. The 30 day Completion Time is based on the availability of the second subsystem, the low probability of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, and the amount of time available after the event for operator action to prevent hydrogen accumulation from exceeding this limit.

Required Action A.1 has been modified by a Note indicating the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one subsystem is inoperable. This allowance is provided because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the low probability of the failure of the OPERABLE subsystem, and the amount of time available after a postulated LOCA for operator action to prevent exceeding the flammability limit.

#### B.1 and B.2

#### - REVIEWER'S NOTE -

This Condition is only allowed for units with an alternate hydrogen control system acceptable to the technical staff.

With two [drywell purge] subsystems inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by [one division of the hydrogen ignitors]. The

#### ACTIONS (continued)

1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist.

#### - REVIEWER'S NOTE -

The following is to be used if a non-Technical Specification alternate hydrogen control function is used to justify this Condition: In addition, the alternate hydrogen control system capability must be verified once per 12 hours thereafter to ensure its continued availability.

[Both] the [initial] verification may [and all subsequent verifications] may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two [drywell purge] subsystems inoperable for up to 7 days. Seven days is a reasonable time to allow two [drywell purge] subsystems to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit.

#### <u>C.1</u>

If any Required Action and the required Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

#### SURVEILLANCE <u>SR</u> REQUIREMENTS

#### SR 3.6.3.3.1

Operating each [drywell purge] subsystem for  $\ge$  15 minutes ensures that each subsystem is OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, compressor failure, or excessive vibration can be detected for corrective action. The 92 day Frequency is consistent with Inservice Testing Program Frequencies, operating experience, the known reliability of the compressor and controls, and the two redundant subsystems available.

#### SURVEILLANCE REQUIREMENTS (continued)

# [<u>SR 3.6.3.3.2</u>

Verifying that each [drywell purge] subsystem flow rate is  $\geq$  [500] scfm ensures that each subsystem is capable of maintaining drywell hydrogen concentrations below the flammability limit. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. ]

#### REFERENCES 1. Regulatory Guide 1.7, Revision [1].

2. FSAR, Section [6.2.5].

# B 3.6 CONTAINMENT SYSTEMS

# B 3.6.4.1 [Secondary Containment]

# BASES

BACKGROUND	The function of the [secondary containment] is to contain, dilute, and hold up fission products that may leak from primary containment following a Design Basis Accident (DBA). In conjunction with operation of the Standby Gas Treatment (SGT) System and closure of certain valves whose lines penetrate the [secondary containment], the [secondary containment] is designed to reduce the activity level of the fission products prior to release to the environment and to isolate and contain fission products that are released during certain operations that take place inside primary containment, when primary containment is not required to be OPERABLE, or that take place outside primary containment.
	The [secondary containment] is a structure that completely encloses the primary containment and those components that may be postulated to contain primary system fluid. This structure forms a control volume that serves to hold up and dilute the fission products. It is possible for the pressure in the control volume to rise relative to the environmental pressure (e.g., due to pump/motor heat load additions). To prevent ground level exfiltration while allowing the [secondary containment] to be designed as a conventional structure, the [secondary containment] requires support systems to maintain the control volume pressure at less than the external pressure. Requirements for these systems are specified separately in LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Standby Gas Treatment (SGT) System."
APPLICABLE SAFETY ANALYSES	There are three principal accidents for which credit is taken for [secondary containment] OPERABILITY. These are a LOCA (Ref. 1), a fuel handling accident [involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous [] days)] inside primary containment (Ref. 2), and a fuel handling accident [involving handling recently irradiated fuel] in the auxiliary building (Ref. 3). The [secondary containment] performs no active function in response to each of these limiting events; however, its leak tightness is required to ensure that the release of radioactive materials from the primary containment is restricted to those leakage paths and associated leakage rates assumed in the accident analysis, and that fission products entrapped within the [secondary containment] structure will be treated by the SGT System prior to discharge to the environment.

# APPLICABLE SAFETY ANALYSES (continued)

[Secondary containment] satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO An OPERABLE [secondary containment] provides a control volume into which fission products that bypass or leak from primary containment, or are released from the reactor coolant pressure boundary components located in [secondary containment], can be diluted and processed prior to release to the environment. For the [secondary containment] to be considered OPERABLE, it must have adequate leak tightness to ensure that the required vacuum can be established and maintained.

# APPLICABILITY In MCDES 1, 2, and 3, a LOCA could lead to a fission product release to primary containment that leaks to [secondary containment]. Therefore, [secondary containment] OPERABILITY is required during the same operating conditions that require primary containment OPERABILITY.

In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODIES. Therefore, maintaining [secondary containment] OPERABLE is not required in MODE 4 or 5 to ensure a control volume, except for other situations for 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 in the [primary or secondary containment].

[Due to radioactive decay, secondary containment is only required to be OPE:RABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous [] days).]

- REVIEWER'S NOTE -

The addition of the term "recently" associated with handling irradiated fuel in all of the containment function Technical Specification requirements is only applicable to those licensees who have demonstrated by analysis that after sufficient radioactive decay has occurred, off-site doses resulting from a fuel handling accident remain below the Standard Review Plan limits (well within 10CFR100).

Additionally, licensees adding the term "recently" must make the following commitment which is consistent with draft NUMARC 93-01, Revision 3, Section 11.2.6 "Safety Assessment for Removal of Equipment from

#### APPLICABILITY (continued)

Service During Shutdown Conditions", subheading "Containment -Primary (PWR)/Secondary (BWR)".

"The following guidelines are included in the assessment of systems removed from service during movement of irradiated fuel:

- During fuel handling/core alterations, ventilation system and radiation monitor availability (as defined in NUMARC 91-06) should be assessed, with respect to filtration and monitoring of releases from the fuel. Following shutdown, radioactivity in the fuel decays away fairly rapidly. The basis of the Technical Specification operability amendment is the reduction in doses due to such decay. The goal of maintaining ventilation system and radiation monitor availability is to reduce doses even further below that provided by the natural decay.

- A single normal or contingency method to promptly close primary or secondary containment penetrations should be developed. Such prompt methods need not completely block the penetration or be capable of resisting pressure.

The purpose of the "prompt methods" mentioned above are to enable ventilation systems to draw the release from a postulated fuel handling accident in the proper direction such that it can be treated and monitored."

#### ACTIONS

# <u>A.1</u>

If [secondary containment] is inoperable, it must be restored to OPERABLE status within 4 hours. The 4 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining [secondary 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 and B.2

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 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

#### ACTIONS (continued)

within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

#### [ C.1 and C.2

Movement of [recently] irradiated fuel assemblies in the [primary or secondary containment] and OPDRVs can be postulated to cause significant 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. Therefore, movement of [recently] irradiated fuel assemblies must be immediately suspended if the [secondary containment] is inoperable.

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

#### SURVEILLANCE [SR 3.6.4.1.1 REQUIREMENTS

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.]

#### SURVEILLANCE REQUIREMENTS (continued)

#### SR 3.6.4.1.2 and SR 3.6.4.1.3

Verifying that [secondary containment] equipment hatches and one access door in each access opening 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. [An access opening contains one inner and one outer door. In some cases, [secondary] containment access openings are shared such that a [secondary] containment barrier may have multiple inner or multiple outer doors. The intent is to not breach the [secondary] containment at any time when [secondary] containment is required. This is achieved by maintaining the inner or outer portion of the barrier closed at all times.] However, all [secondary] containment access doors are normally kept closed, except when the access opening is being used for entry and exit or when maintenance is being performed on an access opening. 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 indications of door and hatch status that are available to the operator.

[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  $\geq$ [0.25] inches of vacuum water gauge in  $\leq$  [120] seconds and maintain pressure in the [secondary] containment at  $\geq$  [0.266] inches of vacuum water gauge for 1 hour at a flow rate < [4000] 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 the [secondary] containment can be drawn down to ≥ [0.25] inches of vacuum water gauge in ≤ [120] seconds using one SGT subsystem. SR 3.6.4.1.5

# SURVEILLANCE REQUIREMENTS (continued)

	demonstrates that the pressure in the [secondary] containment can be maintained $\geq$ [0.266] inches of vacuum water gauge for one hour using one SGT subsystem at a flow rate $\leq$ [4000] cfm. The 1 hour test period allows [secondary] containment to be in thermal equilibrium at steady state conditions. The primary purpose of these SR[s] is to ensure [secondary] containment boundary integrity. The secondary purpose of these SR[s] 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 of ensuring OPERABILITY of the SGT System. These SR[s] need not be performed with each SGT subsystem. The SGT subsystem used for these Surveillance[s] 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 Surveillance[s] relative to the [secondary] containment OPERABILITY. Operating experience has shown the [secondary] containment boundary usually passes these Surveillance[s] when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.
REFERENCES	1. FSAR, Section [15.6.5].
	2. FSAR, Section [15.7.6].
	3. FSAR, Section [15.7.4].

#### B 3.6 CONTAINMENT SYSTEMS

#### B 3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

#### BASES

## BACKGROUND

The function of the SCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Ref. 1). Secondary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that fission products that leak from primary containment following a DBA, that are released during certain operations when primary containment is not required to be OPERABLE, or that take place outside primary containment, are maintained within the secondary containment boundary.

The OPERABILITY requirements for SCIVs help ensure that an adequate secondary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), and blind flanges are considered passive devices. Check valves or other automatic valves designed to close without operator action following an accident are considered active devices. Isolation barrier(s) for the penetration are discussed in Reference 2.

Automatic SCIVs close on a secondary containment isolation signal to establish a boundary for untreated radioactive material within secondary containment following a DBA or other accidents.

Other penetrations are isolated by the use of valves in the closed position or blind flanges.

APPLICABLE SAFETY ANALYSES The SCIVs must be OPERABLE to ensure the secondary containment barrier to fission product releases is established. The principal accidents for which the secondary containment boundary is required are a loss of coolant accident (Ref. 1), a fuel handling accident [involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous [] days)] inside primary containment (Ref. 3), and a fuel handling accident [involving handling recently irradiated fuel] in the auxiliary building (Ref. 4). The secondary containment performs no active function in response to each of these limiting events, but the boundary established by SCIVs is required to ensure that leakage from

#### APPLICABLE SAFETY ANALYSES (continued)

the primary containment is processed by the Standby Gas Treatment (SGT) System before being released to the environment.

Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment so that they can be treated by the SGT System prior to discharge to the environment.

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

LCO SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs.

The power operated, automatic isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in Reference 5.

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are closed or open in accordance with appropriate administrative controls, automatic SCIVs are de-activated and secured in their closed position, and blind flanges are in place. These passive isolation valves or devices are listed in Reference 5.

# APPLICABILITY In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, OPERABILITY of SCIVs is required.

In MODES 4 and 5, the probability and consequences of these events are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs 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. Moving [recently] irradiated fuel assemblies in the [primary or secondary containment] may also occur in MODES 1, 2, and 3. [Due to radioactive decay, SCIVs are only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous [] days).]

#### ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when the need for [secondary containment] isolation is indicated.

The second Note provides clarification that for the purpose of this LCO separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable SCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The third Note ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable SCIV.

#### A.1 and A.2

In the event that there are one or more penetration flow paths with one SCIV inoperable, the affected penetration flow path(s) must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criteria are a closed and de-activated automatic SCIV, a closed manual valve, and a blind flange. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available device to secondary containment. This Required Action must be completed within the 8 hour Completion Time. The specified time period is reasonable considering the time required to isolate the penetration and the low probability of a DBA, which requires the SCIVs to close, occurring during this short time.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that secondary containment penetrations required to be isolated following an accident, but no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that the affected penetration remains isolated.

#### ACTIONS (continued)

Required Action A.2 is modified by two Notes. Note 1 applies to devices located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or othenvise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

#### <u>B.1</u>

With two SCIVs in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 4 hours. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the low probability of a DBA, which requires the SCIVs to close, occurring during this short time.

The Condition has been modified by a Note stating that Condition B is only applicable to penetration flow paths with two isolation valves. This clarifies that only Condition A is entered if one SCIV is inoperable in each of two penetrations.

#### C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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.

#### **ACTIONS** (continued)

#### D.1 and D.2

If any Required Action and associated Completion Time cannot be met, the plant must be placed in a condition in which the LCO does not apply. If applicable, the 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, action must be immediately initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action D.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 movement of [recently] irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

#### SURVEILLANCE REQUIREMENTS

# SR 3.6.4.2.1

This SR verifies each secondary containment isolation manual valve and blind flange that is not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the [secondary containment] boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those SCIVs in [secondary containment] that are capable of being mispositioned are in the correct position.

Since these SCIVs are readily accessible to personnel during normal unit operation and verification of their position is relatively easy, the 31 day Frequency was chosen to provide added assurance that the SCIVs are in the correct positions. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

Two Notes have been added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by

#### SURVEILLANCE REQUIREMENTS (continued)

administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these SCIVs, once they have been verified to be in the proper position, is low.

A second Note has been included to clarify that SCIVs that are open under administrative controls are not required to meet the SR during the time the SCIVs are open.

#### <u>SR 3.6.4.2.2</u>

Verifying the isolation time of each power operated, automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR are [in accordance with the Inservice Testing Program or 92 days].

#### SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a [secondary containment] isolation signal is required to prevent leakage of radioactive material from [secondary containment] following a DBA or other accidents. This SR ensures that each automatic SCIV will actuate to the isolation position on a [secondary containment] isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.2.5 overlaps this SR to provide complete testing of the safety function. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

- REFERENCES 1. FSAR, Section [15.6.5].
  - 2. FSAR, Section [6.2.3].
  - 3. FSAR, Section [15.7.6].
  - 4. FSAR, Section [15.7.4].

REFERENCES (continued)

5. FSAR, Section [].

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#### B 3.6 CONTAINMENT SYSTEMS

#### B 3.6.4.3 Standby Gas Treatment (SGT) System

#### BASES

BACKGROUND	The SGT System is required by 10 CFR 50, Appendix A, GDC 41, "Containment Atmosphere Cleanup" (Ref. 1). The function of the SGT System is to ensure that radioactive materials that leak from the primary containment into the secondary containment following a Design Basis Accident (DBA) are filtered and adsorbed prior to exhausting to the environment.
	The SGT System consists of two fully redundant subsystems, each with its own set of ductwork, dampers, charcoal filter train, and controls.
	Each charcoal filter train consists of (components listed in order of the direction of the air flow):
	a. A moisture separator,
	b. An electric heater,
	c. A prefilter,
	d. A high efficiency particulate air (HEPA) filter,
	e. A charcoal adsorber,
	f. A second HEPA filter, and
	g. A centrifugal fan with inlet flow control vanes.
	The sizing of the SGT System equipment and components is based on the results of an infiltration analysis, as well as an exfiltration analysis of the auxiliary and enclosure building structures. The internal pressure of the SGT System boundary region is maintained at a negative pressure of [0.25] inch water gauge when the system is in operation, which represents the internal pressure required to ensure zero exfiltration of air from the building when exposed to a [10] mph wind blowing at an angle of [45]° to the building.
	The moisture separator is provided to remove entrained water in the air,

while the electric heater reduces the relative humidity of the airstream to less than [70]% (Ref. 2). The prefilter removes large particulate matter, while the HEPA filter is provided to remove fine particulate matter and

# BACKGROUND (continued)

·	protect the charcoal from fouling. The charcoal adsorber removes gaseous elemental iodine and organic iodides, and the final HEPA filter is provicled to collect any carbon fines exhausted from the charcoal adsorber.
	The SGT System automatically starts and operates in response to actuation signals indicative of conditions or an accident that could require operation of the system. Following initiation, both enclosure building recirculation fans and both charcoal filter train fans start. SGT System flows are controlled by modulating inlet vanes installed on the charcoal filter train exhaust fans and two position volume control dampers installed in branch ducts to individual regions of the secondary containment.
APPLICABLE SAFETY ANALYSES	The design basis for the SGT System is to mitigate the consequences of a loss of coolant accident and fuel handling accidents. [Due to radioactive decay, the SGT System is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous [] days).] (Ref. 3). For all events analyzed, the SGT System is shown to be automatically initiated to reduce, via filtration and adsorption, the radioactive material released to the environment.
	The SGT System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Following a DBA, a minimum of one SGT subsystem is required to maintain the secondary containment at a negative pressure with respect to the environment and to process gaseous releases. Meeting the LCO requirements for two operable subsystems ensures operation of at least one SGT subsystem in the event of a single active failure.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, SGT System OPERABILITY is required during these MODES.
	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 in the [primary or secondary containment]. [Due to radioactive decay, the

#### APPLICABILITY (continued)

SGT System is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous [] days).]

#### ACTIONS

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 and B.2

A.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 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.

#### 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 a significant amount of 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

#### ACTIONS (continued)

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

#### <u>D.1</u>

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, actions are required to enter LCO 3.0.3 immediately.

#### 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.

Required Action E.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 movement of [recently] irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

#### SURVEILLANCE REQUIREMENTS

#### SR 3.6.4.3.1

Operating each SGT subsystem for  $\geq$  [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  $\geq$  [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.

#### 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 efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specified test frequencies and additional information are discussed in detail in the VFTP.

#### SR 3.6.4.3.3

This SR requires verification that each SGT subsystem 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 when performed at the [18] month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

#### [<u>SR 3.6.4.3.4</u>

This SR requires verification that the SGT filter cooler 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 when performed at the [18] month Frequency, 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.

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2. IFSAR, Section [6.2.3].

3. FSAR, Section [15.6.5].

#### B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.1 Drywell

#### BASES

# BACKGROUND

The drywell houses the reactor pressure vessel (RPV), the reactor coolant recirculating loops, and branch connections of the Reactor Coolant System (RCS), which have isolation valves at the primary containment boundary. The function of the drywell is to maintain a pressure boundary that channels steam from a loss of coolant accident (LOCA) to the suppression pool, where it is condensed. Air forced from the drywell is released into the primary containment. The pressure suppression capability assures that peak LOCA temperature and pressure in the primary containment are within design limits. The drywell also protects accessible areas of the containment from radiation originating in the reactor core and RCS.

To ensure the drywell pressure suppression capability, the drywell bypass leakage must be minimized to prevent overpressurization of the primary containment during the drywell pressurization phase of a LOCA. This requires periodic testing of the drywell bypass leakage, confirmation that the drywell air lock is leak tight, OPERABILITY of the drywell isolation valves (DIVs), and confirmation that the drywell vacuum relief valves are closed.

The isolation devices for the drywell penetrations are a part of the drywell barrier. To maintain this barrier:

- a. The drywell air lock is OPERABLE except as provided in LCO 3.6.5.2, "Drywell Air Lock,"
- b. The drywell penetrations required to be closed during accident conditions are either:
  - 1. Capable of being closed by an OPERABLE automatic DIV or
  - 2. Closed by manual valves, blind flanges, or de-activated automatic valves secured in closed positions except as provided in LCO 3.6.5.3, "Drywell Isolation Valves (DIVs)," and
- c. The Drywell Vacuum Relief System is OPERABLE except as provided in LCO 3.6.5.6, "Drywell Vacuum Relief System."

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BACKGROUND (continued)	
	This Specification is intended to ensure that the performance of the drywell in the event of a DBA meets the assumptions used in the safety analyses (Ref. 1).
APPLICABLE SAFETY ANALYSES	Analytical methods and assumptions involving the drywell are presented in Reference 1. The safety analyses assume that for a high energy line break inside the drywell, the steam is directed to the suppression pool through the horizontal vents where it is condensed. Maintaining the pressure suppression capability assures that safety analyses remain valid and that the peak LOCA temperature and pressure in the primary containment are within design limits.
	The drywell satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Maintaining the drywell OPERABLE is required to ensure that the pressure suppression design functions assumed in the safety analyses are met. The drywell is OPERABLE if the drywell structural integrity is intact and the bypass leakage is within limits, except prior to the first startup after performing a required drywell bypass leakage test. At this time, the drywell bypass leakage must be $\leq$ [10%] of the drywell bypass leakage limit.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the drywell is not required to be OPERABLE in MODES 4 and 5.
ACTIONS	<u>A.1</u>
	In the event the drywell is inoperable, it must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining the drywell OPERABLE during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring drywell OPERABILITY) occurring during periods when the drywell is inoperable is minimal. Also, the Completion Time is the same as that applied to inoperability of the primary containment in LCO 3.6.1.1, "Primary Containment."
## ACTIONS (continued)

## B.1 and B.2

If the drywell cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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 <u>SR 3.6.5.1.1</u> REQUIREMENTS

The analyses in Reference 2 are based on a maximum drywell bypass leakage. This Surveillance ensures that the actual drywell bypass leakage is less than or equal to the acceptable  $A/\sqrt{k}$  design value of [1.0] ft<sup>2</sup> assumed in the safety analysis. As left drywell bypass leakage, prior to the first startup after performing a required drywell bypass leakage test, is required to be < [10%] of the drywell bypass leakage limit. At all other times between required drywell leakage rate tests, the acceptance criteria is based on design A/ $\sqrt{k}$ . At the design A/ $\sqrt{k}$  the containment temperature and pressurization response are bounded by the assumptions of the safety analysis. The leakage test is performed every [18] months, consistent with the difficulty of performing the test, risk of high radiation exposure, and the remote possibility that a component failure that is not identified by some other drywell or primary containment SR might occur. Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

# SR 3.6.5.1.2

The exposed accessible drywell interior and exterior surfaces are inspected to ensure there are no apparent physical defects that would prevent the drywell from performing its intended function. This SR ensures that drywell structural integrity is maintained. The [40] month Frequency was chosen so that the interior and exterior surfaces of the drywell can be inspected at every other refueling outage. Due to the passive nature of the drywell structure, the [40] month Frequency is sufficient to identify component degradation that may affect drywell structural integrity.

REFERENCES 1. FSAR, Chapter [6] and Chapter [15].

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## B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.2 Drywell Air Lock

# BASES

# BACKGROUND The drywell air lock forms part of the drywell boundary and provides a means for personnel access during MODES 2 and 3 during low power phase of unit startup. For this purpose, one double door drywell air lock has been provided, which maintains drywell isolation during personnel entry and exit from the drywell. Under the normal unit operation, the drywell air lock is kept sealed. The air pressure in the seals is maintained > [60] psig by the seal air flask and pneumatic system, which is maintained at a pressure > [90] psig.

The drywell air lock is designed to the same standards as the drywell boundary. Thus, the drywell air lock must withstand the pressure and temperature transients associated with the rupture of any primary system line inside the drywell and also the rapid reversal in pressure when the steam in the drywell is condensed by the Emergency Core Cooling System flow following loss of coolant accident flooding of the reactor pressure vessel (RPV). It is also designed to withstand the high temperature associated with the break of a small steam line in the drywell that does not result in rapid depressurization of the RPV.

The air lock is nominally a right circular cylinder, [10] ft in diameter, with doors at each end that are interlocked to prevent simultaneous opening. During periods when the drywell is not required to be OPERABLE, the air lock interlock mechanism may be disabled, allowing both doors of the air lock to remain open for extended periods when frequent drywell entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA).

The air lock is provided with limit switches on both doors that provide control room indication of door position. Additionally, control room indication is provided to alert the operator whenever an air lock interlock mechanism is defeated.

The drywell air lock forms part of the drywell pressure boundary. Not maintaining air lock OPERABILITY may result in degradation of the pressure suppression capability, which is assumed to be functional in the unit safety analyses. The drywell air lock does not need to meet the requirements of 10 CFR 50, Appendix J (Ref. 1), since it is not part of the primary containment leakage boundary. However, it is prudent to specify a leakage rate requirement for the drywell air lock. A seal leakage rate

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BACKGROUND (continued)		
	limit of $\leq$ 200 scfh and an air lock overall leakage rate limit of $\leq$ 200 scfh, at pressure $\geq$ P <sub>a</sub> (11.5 psig), have been established to assure the integrity of the seals.	
APPLICABLE SAFETY ANALYSES	Analytical methods and assumptions involving the drywell are presented in Reference 2. The safety analyses assume that for a high energy line break inside the drywell, the steam is directed to the suppression pool through the horizontal vents where it is condensed. Since the drywell air lock is part of the drywell pressure boundary, its design and maintenance are essential to support drywell OPERABILITY, which assures that the safety analyses are met.	
	The drywell air lock satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).	
LCO	The drywell air lock forms part of the drywell pressure boundary. The air lock safety function assures that steam resulting from a DBA is directed to the suppression pool. Thus, the air lock's structural integrity is essential to the successful mitigation of such an event.	
	The air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPEFIABLE, air lock leakage must be within limits, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of the drywell does not exist when the drywell is required to be OPEFIABLE.	
	Closure of a single door in the air lock is necessary to support drywell OPEFABILITY following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for entry into and exit from the drywell.	
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the primary containment. 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, the drywell air lock is not required to be OPERABLE in MODES 4 and 5.	

Drywell Air Lock B 3.6.5.2

## BASES

#### **ACTIONS**

The ACTIONS are modified by Note 1 that allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed to repair. If the inner door is inoperable, however, then there is a short time during which the drywell boundary is not intact (during access through the outer door). The ability to open the OPERABLE door, even if it means the drywell boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the drywell during the short time in which the OPERABLE door is expected to be open. The OPERABLE door must be immediately closed after each entry and exit.

The ACTIONS are modified by a second Note, which ensures appropriate remedial actions are taken when necessary. Pursuant to LCO 3.0.6, ACTIONS are not required even if the drywell is exceeding its bypass leakage limit. Therefore, the Note is added to require ACTIONS for LCO 3.6.5.1 to be taken in this event.

## A.1, A.2, and A.3

With one drywell air lock door inoperable, the OPERABLE door must be verified closed (Required Action A.1). This ensures that a leak tight drywell barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.5.1, "Drywell," which requires that the drywell be restored to OPERABLE status within 1 hour.

In addition, the air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The Completion Time is considered reasonable for locking the OPERABLE air lock door, considering that the OPERABLE door is being maintained closed.

Required Action A.3 verifies that the air lock has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable drywell boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls that ensure that the OPERABLE air lock door remains closed.

The Required Actions are modified by two Notes. Note 1 ensures only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. The exception of the Note does not affect tracking the Completion Times from the initial entry into Condition A; only the requirement to comply with the Required

## ACTIONS (continued)

Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls. Drywell entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside the drywell that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-required activities) if the drywell was entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the drywell during the short time that the OPERABLE door is expected to be open.

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

With the drywell air lock interlock mechanism inoperable, the Required Actions and associated Completion Times consistent with Condition A are applicable.

The Required Actions are modified by two Notes. Note 1 ensures only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. Note 2 allows entry and exit into the drywell under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

# C.1, C.2, and C.3

With the air lock inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be immediately initiated to evaluate drywell bypass leakage using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the drywell inoperable if both doors in an air lock have failed a seal test or the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), drywell remains OPERABLE, yet only 1 hour (per LCO 3.6.5.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall drywell leakage rate can still be within limits.

Required Action C.2 requires that one door in the drywell air lock must be verified to be closed. This Required Action must be completed within the 1 hour Completion Time. This specified time period is consistent with the

## ACTIONS (continued)

ACTIONS of LCO 3.6.5.1, which requires that the drywell be restored to OPERABLE status within 1 hour.

Additionally, the air lock must be restored to OPERABLE status within 24 hours. The 24 hour Completion Time is reasonable for restoring an inoperable air lock to OPERABLE status, considering that at least one door is maintained closed in the air lock.

## D.1 and D.2

If the inoperable drywell air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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 3.6.5.2.1

This SR requires a test be performed to verify seal leakage of the drywell air lock doors at pressures  $\geq$  [11.5] psig. A seal leakage rate limit of  $\leq$  [200] scfh has been established to ensure the integrity of the seals. The Surveillance is only required to be performed once after each closing. The Frequency of 72 hours is based on operating experience and is considered adequate in view of the other indications available to plant operations personnel that the seal is intact.

## SR 3.6.5.2.2

Every 7 days the drywell air lock seal air flask pressure is verified to be  $\geq$  [90] psig to ensure that the seal system remains viable. It must be checked because it could bleed down during or following access through the air lock, which occurs regularly. The 7 day Frequency has been shown to be acceptable, based on operating experience, and is considered adequate in view of the other indications to the plant operations personnel that the seal air flask pressure is low.

## <u>SR 3.6.5.2.3</u>

The air lock door interlock is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of the

## SURVEILLANCE REQUIREMENTS (continued)

air lock are designed to withstand the maximum expected post accident drywell pressure, closure of either door will support drywell OPEFIABILITY. Thus, the door interlock feature supports drywell OPEFIABILITY while the air lock is being used for personnel transit in and out of the drywell. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is only challenged when drywell is entered, this test is only required to be performed once every [18] months. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the [18] month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The Surveillance is modified by a Note requiring the Surveillance to be performed only upon entry into the drywell.

## SR 3.6.5.2.4

This SR requires a test to be performed to verify overall air lock leakage of the drywell air lock at pressures  $\geq$  [11.5] psig. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the [18] month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR has been modified by a Note indicating that an inoperable air lock door does not invalidate the previous successful performance of an overall air lock leakage test. This is considered reasonable, since either air lock door is capable of providing a fission product barrier in the event of a DBA.

## <u>SR 3.6.5.2.5</u>

This SR ensures that the drywell air lock seal pneumatic system pressure does not decay at an unacceptable rate. The air lock seal will support

## SURVEILLANCE REQUIREMENTS (continued)

drywell OPERABILITY down to a pneumatic pressure of [90] psig. Since the air lock seal air flask pressure is verified in SR 3.6.5.2.2 to be  $\geq$  [90] psig, a decay rate  $\leq$  [30] psig over [10] days is acceptable. The [10] day interval is based on engineering judgment, considering that there is no postulated DBA where the drywell is still pressurized [10] days after the event.

The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

- REFERENCES 1. 10 CFR 50, Appendix J.
  - 2. FSAR, Chapters [6 and 15].

# B 3.6 CONTAINMENT SYSTEMS

## B 3.6.5.3 Drywell Isolation Valve[s]

## BASES

# BACKGROUND

The drywell isolation valves, in combination with other accident mitigation systems, function to ensure that steam and water releases to the drywell are channeled to the suppression pool to maintain the pressure suppression function of the drywell.

The OPERABILITY requirements for drywell isolation valves help ensure that valves are closed, when required, and isolation occurs within the time limits specified for those isolation valves designed to close automatically. Therefore, the OPERABILITY requirements support minimizing drywell bypass leakage assumed in the safety analysis (Ref. 1) for a DBA. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no credible single failure or malfunction of an active component can result in a loss of isolation.

The Drywell Vacuum Relief System valves serve a dual function, one of which is drywell isolation. However, since the other safety function of vacuum relief would not be available if the normal drywell isolation valve actions were taken, the drywell isolation valve OPERABILITY requirements are not applicable to the Drywell Vacuum Relief System isolation valves. Similar surveillance requirements in the LCO for Drywell Vacuum Relief System provide assurance that the isolation capability is available without conflicting with the vacuum relief function.

The Drywell Vent and Purge System is a high capacity system with a [20] inch line, which has isolation valves covered by this LCO. The system supplies filtered outside air directly to the drywell through two lines, each containing two primary containment isolation valves (PCIVs) and two drywell isolation valves called drywell purge isolation valves. The drywell air is exhausted through a line also containing two drywell purge isolation valves by means of two fan units, which are part of the Containment Cooling System charcoal filter trains located inside primary containment. After the air is conditioned and filtered, it is exhausted through two PCIVs. The system is used to remove trace radioactive airborne products prior to personnel entry. The Drywell Vent and Purge

#### BACKGROUND (continued)

System is seldom used in MODE 1, 2, or 3; therefore, the drywell purge isolation valves are seldom open during power operation.

The drywell purge isolation valves fail closed on loss of instrument air or power. The drywell purge isolation valves are fast closing valves (approximately [4] seconds). These valves are qualified to close against the differential pressure induced by a loss of coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES This LCO is intended to ensure that releases from the core do not bypass the suppression pool so that the pressure suppression capability of the drywell is maintained. Therefore, as part of the drywell boundary, drywell isolation valve OPERABILITY minimizes drywell bypass leakage. Therefore, the safety analysis of any event requiring isolation of the drywell is applicable to this LCO.

The DBA resulting in a release of steam, water, or radioactive material within the drywell is a LOCA. In the analysis for these accidents, it is assured that drywell isolation valves either are closed or function to close within the required isolation time following event initiation. Analyses (Ref. 1) also assumed a 4 second drywell purge isolation valve closure time following a 1 second delay prior to closure.

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

LCO

The drywell isolation valve safety function is to form a part of the drywell boundary.

The drywell isolation valves are required to have isolation times of automatic drywell isolation valves within limits, automatic drywell isolation valves actuate on an automatic isolation signal, drywell isolation manual valves closed, purge valves closed, and 20 inch purge valves blocked to restrict maximum valve opening. While the Drywell Vacuum Relief System valves isolate drywell penetrations, they are excluded from this Specification. Controls on their isolation function are adequately addressed in LCO 3.6.5.6, "Drywell Vacuum Relief System." The valves covered by this LCO are included (with their associated stroke time for automatic valves) in Reference 2.

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are closed or open in accordance with appropriate administrative controls, automatic valves are de-activated

BASES	
LCO (continued)	
	and secured in their closed position (including check valves with flow through the valve secured), and blind flanges are in place. These passive isolation valves and devices are those listed in Reference 2.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the primary containment. 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, the drywell isolation valves are not required to be OPERABLE in MODES 4 and 5.
ACTIONS	The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the valve. In this way, the penetration can be rapidly isolated when a need for drywell isolation is indicated.
	The second Note provides clarification that for the purpose of this LCO separate Condition entry is allowed for each penetration flow path.
	The third Note requires the OPERABILITY of affected systems to be evaluated when a drywell isolation valve is inoperable. This ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable drywell isolation valve.
	The fourth Note ensures appropriate remedial actions are taken when the drywell bypass leakage limits are exceeded. Pursuant to LCO 3.0.6, these ACTIONS are not required even when the associated LCO is not met. Therefore, Note 4 is added to require the proper actions be taken.
	A.1 and A.2
	With one or more penetration flow paths with one drywell isolation valve inoperable, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic drywell isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. In this Condition, the remaining OPERABLE drywell isolation valve is adequate to perform the isolation function. However, the overall reliability is reduced because a

## ACTIONS (continued)

single failure in the OPERABLE drywell isolation valve could result in a loss of drywell isolation. The 8 hour Completion Time is acceptable, since the drywell design bypass leakage  $A/\sqrt{k}$  of [1.0] ft<sup>2</sup> would be maintained even with a single failure due to application of ACTIONS Note 4. In addition, the Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting drywell OPERABILITY during MODES 1, 2, and 3.

For affected penetration flow paths that have been isolated in accordance with Required Action A.1, the affected penetrations must be verified to be isolated on a periodic basis. This is necessary to ensure that drywell penetrations that are required to be isolated following an accident, and are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation; rather, it involves verification that those devices outside drywell and capable of potentially being mispositioned are in the correct position. Since these devices are inside primary containment, the time period specified as "prior to entering MODE 2 or 3 from MODE 4, if not performed within the previous 92 days," is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and other administrative controls that will ensure that device misalignment is an unlikely possibility. Also, this Completion Time is consistent with the Completion Time specified for PCIVs in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)."

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment once they have been verified to be in the proper position, is low.

<u>B.1</u>

With one or more penetration flow paths with two drywell isolation valves inoperable, the affected penetration flow path must be isolated. The

## ACTIONS (continued)

method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. The 4 hour Completion Time is acceptable, since the drywell design bypass leakage  $A/\sqrt{k}$  of [1.0] ft<sup>2</sup> is maintained due to application of ACTIONS Note 4. The Completion Time is reasonable, considering the time required to isolate the penetration, and the probability of a DBA, which requires the drywell isolation valves to close, occurring during this short time is very low.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two isolation valves. For penetration flow paths with one drywell isolation valve, Condition A provides the appropriate Required Actions.

# C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be placed in 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 [SR 3.6.5.3.1 REQUIREMENTS

Each [] inch drywell purge isolation valve is required to be verified sealed closed at 31 day intervals. This Surveillance is intended to be used for drywell purge isolation valves that are not qualified to open under accident conditions. This SR is designed to ensure that a gross breach of drywell is not caused by an inadvertent or spurious drywell purge isolation valve opening. Detailed analysis of these [] inch drywell purge valves failed to conclusively demonstrate their ability to close during a LOCA in time to support drywell OPERABILITY. Therefore, these valves are required to be in sealed closed position during MODES 1, 2, and 3. These [] inch drywell purge valves that are sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or removing the air supply to the valve operator. In this application, the term "sealed" has no connotation of leakage within limits. The Frequency is a

## SURVEILLANCE REQUIREMENTS (continued)

result of the NRC resolution of Generic Issue B-24 (Ref. 3) related to purge valve use during unit operations. ]

## [SR 3.6.5.3.2

This SR ensures that the [20] inch drywell purge isolation valves are closed as required or, if open, open for an allowable reason. This SR is intended to be used for drywell purge isolation valves that are fully qualified to close under accident conditions; therefore, these valves are allowed to be open for limited periods of time. This SR has been modified by a Note indicating the SR is not required to be met when the drywell purge supply or exhaust valves are open for pressure control, ALARA or air quality considerations for personnel entry, or surveillances that require the valve to be open [provided the [20] inch containment [purge system supply and exhaust] lines are isolated]. The 31 day Frequency is consistent with the valve requirements discussed under SR 3.6.5.3.1.]

## SR 3.6.5.3.3

This SR requires verification that each drywell isolation manual valve and blind flange that is not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed. The SR helps to ensure that drywell bypass leakage is maintained to a minimum. Since these valves are inside primary containment, the Frequency specified as "prior to entering MODE 2 or 3 from MODE 4, if not performed in the previous 92 days," is appropriate because of the inaccessibility of the drywell isolation valves and because these drywell isolation valves are operated under administrative controls and the probability of their misalignment is low. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

A Note has been included to clarify that valves that are open under administrative controls are not required to meet the SR during the time the valves are open.

# <u>SR 3.6.5.3.4</u>

Verifying that the isolation time of each power operated, automatic drywell isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analysis.

## SURVEILLANCE REQUIREMENTS (continued)

The isolation time and Frequency of this SR are [in accordance with the Inservice Testing Program or 92 days].

## SR 3.6.5.3.5

Verifying that each automatic drywell isolation valve closes on a drywell isolation signal is required to prevent bypass leakage from the drywell following a DBA. This SR ensures each automatic drywell isolation valve will actuate to its isolation position on a drywell isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.1.6 overlaps this SR to provide complete testing of the safety function. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power, since isolation of penetrations would eliminate cooling water flow and disrupt the normal operation of many critical components. Operating experience has shown these components usually pass this Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

#### <u>SR 3.6.5.3.6</u>

Verifying that each [] inch drywell purge valve is blocked to restrict opening to > [50]% is required to ensure that the valves can be closed under DBA conditions within the time limits assumed in the safety analyses.

The [18] month Frequency is appropriate because the blocking devices are typically removed only during a refueling outage.

<ol> <li>FSAR, Table [6.2-44].</li> <li>Generic Issue B-24.</li> </ol>	REFERENCES	1.	FSAR, Section [6.2.4].
		2. 3.	Generic Issue B-24.

# B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.4 Drywell Pressure

# BASES

BACKGROUND	Drywell-to-primary containment differential pressure is an assumed initial condition in the analyses that determine the primary containment thermal hydraulic and dynamic loads during a postulated loss of coolant accident (LOCA).
	If drywell pressure is less than the primary containment airspace pressure, the water level in the weir annulus will increase and, consequently, the liquid inertia above the top vent will increase. This will cause top vent clearing during a postulated LOCA to be delayed, and that would increase the peak drywell pressure. In addition, an inadvertent upper pool dump occurring with a negative drywell-to-primary containment differential pressure could result in overflow over the weir wall.
	The limitation on negative drywell-to-primary containment differential pressure ensures that changes in calculated peak LOCA drywell pressures due to differences in water level of the suppression pool and the drywell weir annulus are negligible. It also ensures that the possibility of weir wall overflow after an inadvertent pool dump is minimized. The limitation on positive drywell-to-primary containment differential pressure helps ensure that the horizontal vents are not cleared with normal weir annulus water level.
APPLICABLE SAFETY ANALYSES	Primary containment performance is evaluated for the entire spectrum of break sizes for postulated LOCAs. Among the inputs to the design basis analysis is the initial drywell internal pressure (Ref. 1). The initial drywell internal pressure affects the drywell pressure response to a LOCA (Ref. 1) and the suppression pool swell load definition (Ref. 2).
	Additional analyses (Refs. 3 and 4) have been performed to show that if initial drywell pressure does not exceed the negative pressure limit, the suppression pool swell and vent clearing loads will not be significantly increased and the probability of weir wall overflow is minimized after an inadvertent upper pool dump.
	Drywell pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES	
LCO	A limitation on the drywell-to-primary containment differential pressure of $[\ge -0.26 \text{ psid and} \le 2.0 \text{ psid}]$ is required to ensure that suppression pool water is not forced over the weir wall, vent clearing does not occur during normal operation, containment conditions are consistent with the safety analyses, and LOCA drywell pressures and pool swell loads are within design values.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining the drywell-to-primary containment differential pressure limitation is not required in MODE 4 or 5.
ACTIONS	<u>A.1</u>
	With drywell-to-primary containment differential pressure not within the limits of the LCO, it must be restored within 1 hour. The Required Action is necessary to return operation to within the bounds of the safety analyses. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.5.1, "Drywell," which requires that the drywell be restored to OPERABLE status within 1 hour.
	B.1 and B.2
	If drywell-to-primary containment differential pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 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	<u>SR 3.6.5.4.1</u>
	This SR provides assurance that the limitations on drywell-to-primary containment differential pressure stated in the LCO are met. The 12 hour Frequency of this SR was developed, based on operating experience related to trending of drywell pressure variations during the applicable MODES and to assessing proximity to the specified LCO pressure limits. Furthermore, the 12 hour Frequency is considered adequate in view of

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# SURVEILLANCE REQUIREMENTS (continued)

other indications available in the control room, including alarms, to alert the operator to an abnormal drywell pressure condition.

- REFERENCES 1. FSAR, Section [6.2.1].
  - 2. FSAR, Section [3.8].
  - 3. FSAR, Section [6.2.1.1.6].
  - 4. FSAR, Section [6.2.7].

# B 3.6 CONTAINMENT SYSTEMS

# B 3.6.5.5 Drywell Air Temperature

# BASES

BACKGROUND	The drywell contains the reactor vessel and piping, which add heat to the airspace. Drywell coolers remove heat and maintain a suitable environment. The drywell average air temperature affects equipment OPERABILITY, personnel access, and the calculated response to postulated Design Basis Accidents (DBAs). The limitation on drywell average air temperature ensures that the peak drywell temperature during a design basis loss of coolant accident (LOCA) does not exceed the design temperature of [330]°F. The limiting DBA for drywell atmosphere temperature is a small steam line break, assuming no heat transfer to the passive steel and concrete heat sinks in the drywell.
APPLICABLE SAFETY ANALYSES	Primary containment performance for the DBA is evaluated for the entire spectrum of break sizes for postulated LOCAs inside containment (Ref. 1). Among the inputs to the design basis analysis is the initial drywell average air temperature. Increasing the initial drywell average air temperature could change the calculated results of the design bases analysis. The safety analyses (Ref. 1) assume an initial average drywell air temperature of [135]°F. This limitation ensures that the safety analyses remain valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell temperature does not exceed the maximum allowable temperature of [330]°F. The consequence of exceeding this design temperature may result in the degradation of the drywell structure under accident loads. Equipment inside the drywell that is required to mitigate the effects of a DBA is designed and qualified to operate under environmental conditions expected for the accident. Drywell average air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	If the initial drywell average air temperature is less than or equal to the LCO temperature limit, the peak accident temperature can be maintained below the drywell design temperature during a DBA. This ensures the ability of the drywell to perform its design function.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and

## APPLICABILITY (continued)

temperature limitations of these MODES. Therefore, maintaining drywell average air temperature within the limit is not required in MODE 4 or 5.

## ACTIONS

When the drywell average air temperature is not within the limit of the LCO, it must be restored within 8 hours. The Required Action is necessary to return operation to within the bounds of the safety analyses. The 8 hour Completion Time is acceptable, considering the sensitivity of the analyses to variations in this parameter, and provides sufficient time to correct minor problems.

## B.1 and B.2

A.1

If drywell average air temperature cannot be restored to within limit 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 <u>SR 3.6.5.5.1</u> REQUIREMENTS

Verifying that the drywell average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the drywell analysis. Drywell air temperature is monitored in all quadrants and at various elevations. Since the measurements are uniformly distributed, an arithmetic average is an accurate representation of actual drywell average temperature.

The 24 hour Frequency of the SR was developed based on operating experience related to variations in drywell average air temperature variations during the applicable MODES. 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 drywell air temperature condition.

Drywell Air Temperature B 3.6.5.5

BASES

REFERENCES 1. FSAR, Section [6.2].

# B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.6 Drywell Vacuum Relief System

## BASES

# BACKGROUND

The Mark III pressure suppression containment is designed to condense, in the suppression pool, the steam released into the drywell in the event of a loss of coolant accident (LOCA). The steam discharging to the pool carries the noncondensibles from the drywell. Therefore, the drywell atmosphere changes from low humidity air to nearly 100% steam (no air) as the event progresses. When the drywell subsequently cools and depressurizes, noncondensibles in the drywell must be replaced to avoid excessive weir wall overflow into the drywell. Rapid weir wall overflow must be controlled in a large break LOCA, so that essential equipment and systems located above the weir wall in the drywell are not subjected to excessive drag and impact loads. The drywell post-LOCA and the drywell purge vacuum relief subsystems are the means by which noncondensibles are transferred from the primary containment back to the drywell.

The vacuum relief systems are a potential source of bypass leakage (i.e., some of the steam released into the drywell from a LOCA bypasses the suppression pool and leaks directly to the primary containment airspace). Since excessive bypass leakage could degrade the pressure suppression function, the Drywell Vacuum Relief System has been designed with at least two valves in series in each vacuum breaker line. This minimizes the potential for a stuck open valve to threaten drywell OPERABILITY. The [two] drywell purge vacuum relief subsystems use separate [10] inch lines penetrating the drywell, and each subsystem consists of a series arrangement of a motor operated isolation valve and two check valves. The [two] drywell post-LOCA vacuum relief subsystems use a common [10] inch line penetrating the drywell, and each subsystem consists of a motor operated valve in series with a check valve. At least two [10] inch lines must be available to provide adequate relief to control rapid weir wall overflow.

APPLICABLE SAFETY ANALYSES The Drywell Vacuum Relief System must function in the event of a large break LOCA to control rapid weir wall overflow that could cause drag and impact loadings on essential equipment and systems in the drywell above the weir wall. The Drywell Vacuum Relief System is not required to assist in hydrogen dilution or to protect the structural integrity of the drywell following a large break LOCA. Furthermore, their passive operation (remaining closed and not leaking during drywell pressurization) is implicit in all of the LOCA analyses (Ref. 1).

APPLICABLE	SAFETY	ANALYSES	(continued)
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The Drywell Vacuum Relief System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

- LCO The LCO ensures that in the event of a LOCA, [two] drywell post-LOCA and [two] drywell purge vacuum relief subsystems are available to mitigate the potential subsequent drywell depressurization. Each vacuum relief subsystem is OPERABLE when capable of opening at the required setpoint but is maintained in the closed position during normal operation.
- APPLICABILITY In MODES 1, 2, and 3, a Design Basis Accident could cause pressurization of primary containment. Therefore, Drywell Vacuum Relief System OPERABILITY is required during these MODES. 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 Drywell Vacuum Relief System OPERABLE is not required in MODE 4 or 5.

ACTIONS The ACTIONS Note ensures appropriate remedial actions are taken when the drywell bypass leakage limits are exceeded. Pursuant to LCO 3.0.6, these ACTIONS are not required even when the associated LCO is not met. Therefore, the Note is added to require the proper actions be taken.

# <u>A.1</u>

With one or more vacuum relief subsystems open, the subsystem must be closed within 4 hours. This assures that drywell leakage would not result if a postulated LOCA were to occur. The 4 hour Completion Time is acceptable, since the drywell design bypass leakage  $(A/\sqrt{k})$  of [1.0] ft<sup>2</sup> is maintained, and is considered a reasonable length of time needed to complete the Required Action.

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

## B.1 and C.1

With one [or two] drywell post-LOCA vacuum relief subsystems inoperable or one drywell purge vacuum relief subsystem inoperable, for reasons other then being not closed, the inoperable subsystem(s) must be restored to OPERABLE status within 30 days. In these Conditions, the remaining OPERABLE vacuum relief subsystems are adequate to

## ACTIONS (continued)

perform the depressurization mitigation function since two [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.

# D.1 and E.1

With [two] drywell purge vacuum relief subsystems inoperable or with [two] drywell post-LOCA and one drywell purge vacuum relief subsystems inoperable, for reasons other than being not closed, at least one inoperable subsystem must be restored to OPERABLE status within 72 hours. In these Conditions, only one [10] inch line remains available. The 72 hour Completion Time takes into account at least one vacuum relief subsystem is still OPERABLE, a reasonable time for repairs, and the low probability of an event requiring the vacuum relief subsystems to function occurring during this period.

# F.1, F.2, G.1, and G.2

If the inoperable drywell vacuum relief subsystem(s) cannot be closed or restored to OPERABLE status within the required Completion Time, or if two drywell purge vacuum relief subsystems are inoperable, for reasons other than being not closed, and one or two drywell post-LOCA vacuum relief subsystem(s) are inoperable, for reasons other than being not closed, 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 <u>SR 3.6.5.6.1</u> REQUIREMENTS

Each vacuum breaker and its associated isolation valve is verified to be closed to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing the vacuum breaker or associated isolation valve position indication or by verifying that the vacuum breakers are closed when a differential pressure of [1.0] psid between the drywell and primary containment is maintained for 1 hour without makeup. The 7 day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum

## SURVEILLANCE REQUIREMENTS (continued)

breaker or isolation valve status available to the plant personnel, and has been shown to be acceptable through operating experience.

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

## <u>SR 3.6.5.6.2</u>

Each vacuum breaker and its associated isolation 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 vacuum breakers and their associated isolation valves are OPERABLE.

## <u>SR 3.6.5.6.3</u>

Verification of the vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption that the vacuum breaker will open fully at a differential pressure of [1.0] psid is valid. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the [18] month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES 1. FSAR, Section [6.2].

## **B 3.7 PLANT SYSTEMS**

B 3.7.1 [Standby Service Water (SSW)] System and [Ultimate Heat Sink (UHS)]

## BASES

BACKGROUND The [SSW] System is designed to provide cooling water for the removal of heat from unit auxiliaries, such as Residual Heat Removal (RHR) System heat exchangers, standby diesel generators (DGs), and room coolers for Emergency Core Cooling System equipment required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The [SSW] System also provides cooling to unit components, as required, during normal shutdown and reactor isolation modes. During a DBA, the equipment required for normal operation only is isolated from the [SSW] System, and cooling is directed only to safety related equipment.

> The [SSW] System consists of the [UHS], two independent cooling water headers (subsystems A and B), and their associated pumps, piping, valves, and instrumentation. The two [SSW] pumps, or one [SSW] pump and the high pressure core spray service water pump, are sized to provide sufficient cooling capacity to support the required safety related systems during safe shutdown of the unit following a loss of coolant accident (LOCA). Subsystems A and B are redundant and service equipment in [SSW] Divisions 1 and 2, respectively.

The [UHS] consists of two concrete makeup water basins, each containing one cooling tower with two fan cells per basin. The combined basin volume is sized such that sufficient water inventory is available for all [SSW] System post LOCA cooling requirements for a 30 day period with no external makeup water source available (Regulatory Guide 1.27, Ref. 1). Normal makeup for each basin is provided automatically by the Plant Service Water System.

Cooling water is pumped from the cooling tower basins by the two [SSW] pumps to the essential components through the two main redundant supply headers (subsystems A and B). After removing heat from the components, the water is discharged to the cooling towers where the heat is rejected through direct contact with ambient air.

Subsystems A and B supply cooling water to redundant equipment required for a safe reactor shutdown. Additional information on the design and operation of the [SSW] System and [UHS] along with the specific equipment for which the [SSW] System supplies cooling water is provided in the FSAR, Section [9.2.1] and the FSAR, Table [9.2-3] (Refs. 2 and 3, respectively). The [SSW] System is designed to

## BACKGROUND (continued)

withstand a single active or passive failure, coincident with a loss of offsite power, without losing the capability to supply adequate cooling water to equipment required for safe reactor shutdown.

Following a DBA or transient, the [SSW] System will operate automatically without operator action. Manual initiation of supported systems (e.g., suppression pool cooling) is, however, performed for long term cooling operations.

## **APPLICABLE** The volume of each water source incorporated in a [UHS] complex is sized so that sufficient water inventory is available for all [SSW] System SAFETY ANALYSES post LOCA cooling requirements for a 30 day period with no additional makeup water source available (Ref. 1). The ability of the [SSW] System to support long term cooling of the reactor or containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in the FSAR, Sections [9.2.1], [6.2.1.1.3.3.1.6] and Chapter [15], (Refs. 2, 4, and 5, respectively). These analyses include the evaluation of the long term primary containment response after a design basis LOCA. The [SSW] System provides cooling water for the RHR suppression pool cooling mode to limit suppression pool temperature and primary containment pressure following a LOCA. This ensures that the primary containment can perform its intended function of limiting the release of radioactive materials to the environment following a LOCA. The [SSW] System also provides cooling to other components assumed to function during a LOCA (e.g., RHR and Low Pressure Core Spray systems). Also, the ability to provide onsite emergency AC power is dependent on the ability of the [SSW] System to cool the DGs. The safety analyses for long term containment cooling were performed.

as discussed in the FSAR, Sections [6.2.1.1.3.3.1.6] and [6.2.2.3] (Refs. 4 and 6, respectively), for a LOCA, concurrent with a loss of offsite power, and minimum available DG power. The worst case single failure affecting the performance of the [SSW] System is the failure of one of the two standby DGs, which would in turn affect one [SSW] subsystem. The [SSW] flow assumed in the analyses is [7900] gpm per pump to the heat exchanger (FSAR, Table [6.2-2], Ref. 7). Reference 2 discusses [SSW] System performance during these conditions.

The [SSW] System, together with the [UHS], satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES	
LCO	The OPERABILITY of subsystem A (Division 1) and subsystem B (Division 2) of the [SSW] System is required to ensure the effective operation of the RHR System in removing heat from the reactor, and the effective operation of other safety related equipment during a DBA or transient. Requiring both subsystems to be OPERABLE ensures that either subsystem A or B will be available to provide adequate capability to meet cooling requirements of the equipment required for safe shutdown in the event of a single failure.
	A subsystem is considered OPERABLE when:
	a. The associated pump is OPERABLE,
	b. The associated [UHS] is OPERABLE, and
	c. The associated piping, valves, instrumentation, and controls required to perform the safety related function are OPERABLE.
	OPERABILITY of the [UHS] is based on a maximum water temperature of [95]°F with OPERABILITY of each subsystem requiring a minimum basin water level at or above elevation [130 ft 3 inches] mean sea level (equivalent to an indicated level of $\geq$ [7 ft 3 inches]) and four OPERABLE cooling tower fans.
	The isolation of the [SSW] System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the [SSW] System.
	OPERABILITY of the High Pressure Core Spray (HPCS) Service Water System (SWS) is addressed by LCO 3.7.2, "HPCS SWS."
APPLICABILITY	In MODES 1, 2, and 3, the [SSW] System and [UHS] are required to be OPERABLE to support OPERABILITY of the equipment serviced by the [SSW] System and [UHS], and are required to be OPERABLE in these MODES.
	In MODES 4 and 5, the OPERABILITY requirements of the [SSW] System and [UHS] are determined by the systems they support.

# ACTIONS [A.1

If one or more cooling towers have one fan inoperable (i.e., up to one fan per cooling tower inoperable), action must be taken to restore the inoperable cooling tower fan(s) to OPERABLE status within 7 days.

The 7 day Completion Time is reasonable, based on the low probability of an accident occurring during the 7 days that one cooling tower fan is inoperable in one or more cooling towers, the number of available systems, and the time required to complete the Required Action. ]

## [<u>B.1</u>

## - REVIEWER'S NOTE -

The []°F is the maximum allowed UHS temperature value and is based on temperature limitations of the equipment that is relied upon for accident mitigation and safe shutdown of the unit.

With water temperature of the UHS >  $[90]^{\circ}F$ , the design basis assumption associated with initial UHS temperature is bounded provided the temperature of the UHS averaged over the previous 24 hour period is  $\leq$  [90]°F. With the water temperature of the UHS > [90]°F, long term cooling capability of the ECCS loads and DGs may be affected. Therefore, to ensure long term cooling capability is provided to the ECCS loads when water temperature of the UHS is > [90]°F. Required Action B.1 is provided to more frequently monitor the water temperature of the UHS and verify the temperature is  $\leq$  [90]°F when averaged over the previous 24 hour period. The once per hour Completion Time takes into consideration UHS temperature variations and the increased monitoring frequency needed to ensure design basis assumptions and equipment limitations are not exceeded in this condition. If the water temperature of the UHS exceeds [90]°F when averaged over the previous 24 hour period or the water temperature of the UHS exceeds [ ]°F, Condition D must be entered immediately.1

# <u>C.1</u>

If one [SSW] subsystem is inoperable [for reasons other than Condition A], it must be restored to OPERABLE status within 72 hours. With the unit in this condition, the remaining OPERABLE [SSW] subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE [SSW] subsystem could result in loss of [SSW] function. The 72 hour Completion Time was developed taking into account the

# ACTIONS (continued)

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 [SSW] subsystem results in an inoperable DG or RHR shutdown cooling, respectively. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for these components.

# D.1 and D.2

If the [SSW] subsystem cannot be restored to OPERABLE status within the associated Completion Time, or both [SSW] subsystems are inoperable [for reasons other than Condition A], or the [[UHS] is determined inoperable for reasons other than Condition A or B], 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.

# SURVEILLANCE [SR 3.7.1.1 REQUIREMENTS

This SR ensures adequate long term (30 days) cooling can be maintained. With the [UHS] water source below the minimum level, the affected [SSW] subsystem must be declared inoperable. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES. ]

# [<u>SR 3.7.1.2</u>

This SR verifies the water level [in each [SSW] pump well of the intake structure] to be sufficient for the proper operation of the [SSW] pumps (net positive suction head and pump vortexing are considered in determining this limit). The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.]

## SURVEILLANCE REQUIREMENTS (continued)

# [<u>SR\_3.7.1.3</u>

Verification of the [UHS] temperature ensures that the heat removal capability of the [SSW] System is within the assumptions of the DBA analysis. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES. ]

# [<u>SR 3.7.1.4</u>

Operating each cooling tower fan for  $\geq 15$  minutes ensures that all fans are OPERABLE and that all associated controls are functioning properly. It also ensures that fan or motor failure, or excessive vibration can be detected for corrective action. The 31 day Frequency is based on operating experience, the known reliability of the fan units, the redundancy available, and the low probability of significant degradation of the cooling tower fans occurring between Surveillances. ]

# SR 3.7.1.5

Verifying the correct alignment for each manual, power operated, and automatic valve in each [SSW] subsystem flow path provides assurance that the proper flow paths will exist for [SSW] 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. 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.

This SR is modified by a Note indicating that isolation of the [SSW] System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the [SSW] System. As such, when all [SSW] pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the [SSW] System is still OPERABLE.

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

## SURVEILLANCE REQUIREMENTS (continued)

# <u>SR 3.7.1.6</u>

This SR verifies that the automatic isolation valves of the [SSW] System 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. This SR also verifies the automatic start capability of the [SSW] pump and cooling tower fans in each subsystem. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.5.1.6 overlaps this SR to provide complete testing of the safety function.

Operating experience has shown that these components usually pass the SR when performed on the [18] month Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

1.	Regulatory Guide 1.27, Revision 2, January 1976.
2.	FSAR, Section [9.2.1].
3.	FSAR, Table [9.2-3].
4.	FSAR, Section [6.2.1.1.3.3.1.6].
5.	FSAR, Chapter [15].
6.	FSAR, Section [6.2.2.3].
	1. 2. 3. 4. 5. 6.

7. FSAR, Table [6.2-2].

# **B 3.7 PLANT SYSTEMS**

# B 3.7.2 High Pressure Core Spray (HPCS) Service Water System (SWS)

BASES	
BACKGROUND	The HPCS SWS is designed to provide cooling water for the removal of heat from components of the Division 3 HPCS System.
	The HPCS SWS consists of the Ultimate Heat Sink (UHS) Basin A, one cooling water header (subsystem C of the Standby Service Water (SSW) System), and the associated pumps, piping, and valves. The UHS is also considered part of the SSW System (LCO 3.7.1, "[Standby Service Water (SSW)] System and [Ultimate Heat Sink (UHS)]").
	Cooling water is pumped from a UHS water source by the HPCS service water pump to the essential components through the HPCS service water supply header. After removing heat from the components, the water is discharged to the cooling towers, where the heat is rejected through direct contact with ambient air.
	The HPCS SWS specifically supplies cooling water to the Division 3 HPCS diesel generator jacket water coolers and HPCS pump room cooler. The HPCS SWS pump is sized such that it will provide adequate cooling water to the equipment required for safe shutdown. Following a Design Basis Accident or transient, the HPCS SWS will operate automatically and without operator action as described in the FSAR, Section [9.2.1] (Ref. 1).
APPLICABLE SAFETY ANALYSES	The ability of the HPCS SWS to provide adequate cooling to the HPCS System is an implicit assumption for safety analyses evaluated in the FSAR, Chapters [6] and [15] (Refs. 2 and 3, respectively).
	The HPCS SWS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The HPCS SWS is required to be OPERABLE to ensure that the HPCS System will operate as required. An OPERABLE HPCS SWS consists of an OPERABLE UHS; an OPERABLE pump; and an OPERABLE UHS flow path, capable of taking suction from the associated SSW source and transferring the water to the appropriate unit equipment.
	The OPERABILITY of the UHS is specified in LCO 3.7.1. However, the OPERABILITY of the basin cooling tower fans does not affect the OPERABILITY of the HPCS SWS, due to the limited heat removal during its operation.

BASES	
APPLICABILITY	In MODES 1, 2, and 3, the HPCS SWS is required to be OPERABLE to support OPERABILITY of the HPCS System since it is required to be OPERABLE in these MODES.
	In MODES 4 and 5, the OPERABILITY requirements of the HPCS SWS and the UHS are determined by the HPCS System.
ACTIONS	<u>A.1</u>
	When the HPCS SWS is inoperable, the capability of the HPCS System to perform its intended function cannot be ensured. Therefore, if the HPCS SWS is inoperable, the HPCS System must be declared inoperable immediately and Condition C of LCO 3.5.1, "ECCS - Operating," entered.
SURVEILLANCE	<u>SR 3.7.2.1</u>
REQUIREMENTS	This SR ensures that adequate cooling can be maintained. With the UHS water source below the minimum level, the HPCS SWS must be declared inoperable. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.
	<u>SR 3.7.2.2</u>
	Verifying the correct alignment for each manual, power operated, and automatic valve in the HPCS service water flow path provides assurance that the proper flow paths will exist for HPCS service water operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in 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.
	This SR is modified by a Note indicating that isolation of the [HPCS SWS] System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the [HPCS SWS] System. As such, when all [HPCS SWS] pumps, valves, and

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SURVEILLANCE RE	QUIREMENTS (continued)
	piping are OPERABLE, but a branch connection off the main header is is isolated, the [HPCS SWS] System is still OPERABLE.
	The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.
	<u>SR 3.7.2.3</u>
	This SR verifies that the automatic valves of the HPCS SWS 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. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.5.1.5 overlaps this SR to provide complete testing of the safety function.
	Operating experience has shown that these components usually pass the SR when performed at the [18] month Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.
REFERENCES	1. FSAR, Section [9.2.1].
	2. FSAR, Chapter [6].
<u></u>	3. FSAR, Chapter [15].
#### **B 3.7 PLANT SYSTEMS**

#### B 3.7.3 [Control Room Fresh Air (CRFA)] System

#### BASES

# BACKGROUND The [CRFA] System provides a radiologically controlled environment from which the unit can be safely operated following a Design Basis Accident (DBA).

The safety related function of the [CRFA] System used to control radiation exposure consists of two independent and redundant high efficiency air filtration subsystems for treatment of recirculated air or outside supply air. Each subsystem consists of a demister, an electric heater, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section, a second HEPA filter, a fan, and the associated ductwork and dampers. Demisters remove water droplets from the airstream. Prefilters and HEPA filters remove particulate matter that may be radioactive. The charcoal adsorbers provide a holdup period for gaseous iodine, allowing time for decay.

In addition to the safety related standby emergency filtration function, parts of the [CRFA] System are operated to maintain the control room environment during normal operation. Upon receipt of the initiation signal(s) (indicative of conditions that could result in radiation exposure to control room personnel), the [CRFA] System automatically switches to the isolation mode of operation to prevent infiltration of contaminated air into the control room. A system of dampers isolates the control room, and control room air flow is recirculated and processed through either of the two filter subsystems.

The [CRFA] System is designed to maintain the control room environment for a 30 day continuous occupancy after a DBA, without exceeding a 5 rem whole body dose or its equivalent to any part of the body. [CRFA] System operation in maintaining the control room habitability is discussed in the FSAR, Sections [6.5.1] and [9.4.1] (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The ability of the [CRFA] System to maintain the habitability of the control room is an explicit assumption for the safety analyses presented in the FSAR, Chapters [6] and [15] (Refs. 3 and 4, respectively). The isolation mode of the [CRFA] System is assumed to operate following a loss of coolant accident, main steam line break, fuel handling accident [involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous [] days)], and control rod drop

#### APPLICABLE SAFETY ANALYSES (continued)

accident. The radiological doses to control room personnel as a result of the various DBAs are summarized in Reference 4. No single active or passive failure will cause the loss of outside or recirculated air from the control room.

The [CRFA] System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO Two redundant subsystems of the [CRFA] System are required to be OPEIRABLE to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in exceeding a dose of 5 rem to the control room operators in the event of a DBA.

The [CRFA] System is considered OPERABLE when the individual components necessary to control operator exposure are OPERABLE in both subsystems. A subsystem is considered OPERABLE when its associated:

- a. Fan is OPERABLE,
- b. HEPA filter and charcoal adsorber are not excessively restricting flow and are capable of performing their filtration functions, and
- c. Heater, demister, ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

In addition, the control room boundary must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and access doors.

The LCO is modified by a Note allowing the control room boundary to be opened intermittently under administrative controls. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls consist of stationing a dedicated individual at the opening who is in continuous communication with the control room. This individual will have a method to rapidly close the opening when a need for control room isolation is indicated.

# APPLICABILITY In MODES 1, 2, and 3, the [CRFA] System must be OPERABLE to control operator exposure during and following a DBA, since the DBA could lead to a fission product release.

#### APPLICABILITY (continued)

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 [CRFA] 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); and
- b. During movement of [recently] irradiated fuel assemblies in the [primary or secondary containment]. [Due to radioactive decay, the CRFA System is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous [] days).]

#### ACTIONS

<u>A.1</u>

With one [CRFA] subsystem inoperable, the inoperable [CRFA] subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE [CRFA] subsystem is adequate to perform control room radiation protection. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in loss of [CRFA] 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.

<u>B.1</u>

#### - REVIEWER'S NOTE -

Adoption of Condition B is dependent on a commitment from the licensee to have written procedures available describing compensatory measures to be taken in the event of an intentional or unintentional entry into Condition B.

If the control room boundary is inoperable in MODE 1, 2, or 3, the CRFA trains cannot perform their intended functions. Actions must be taken to restore an OPERABLE control room boundary within 24 hours. During the period that the control room boundary is inoperable, appropriate compensatory measures (consistent with the intent of GDC 19) should be utilized to protect control room operators from potential hazards such as radioactive contamination, toxic chemicals, smoke, temperature and

#### ACTIONS (continued)

relative humidity, and physical security. Preplanned measures should be available to address these concerns for intentional and unintentional entry into the condition. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of compensatory measures. The 24 hour Completion Time is a typically reasonable time to diagnose, plan and possibly repair, and test most problems with the control room boundary.

#### C.1 and C.2

In MODE 1, 2, or 3, if the inoperable [CRFA] subsystem or control room boundary cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes 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.

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

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

During movement of [recently] irradiated fuel assemblies in the [primary or secondary containment] or during OPDRVs, if the inoperable [CRFA] subsystem cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE [CRFA] subsystem may be placed in the isolation 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.

Required Action D.1 is modified by a Note alerting the operator to [place the system in the toxic gas protection mode if the toxic gas, automatic transfer capability is inoperable].

An alternative to Required Action D.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require

#### ACTIONS (continued)

isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, movement of [recently] 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.

#### <u>E.1</u>

If both [CRFA] subsystems are inoperable in MODE 1, 2, or 3 for reasons other than an inoperable control room boundary (i.e., Condition B), the [CRFA] System may not be capable of performing the intended function and the unit is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

#### F.1 and F.2

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

During movement of [recently] irradiated fuel assemblies in the [primary or secondary containment] or during OPDRVs, with two [CRFA] subsystems inoperable, action must be taken immediately to suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, movement of [recently] 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

ACTIONS (continued)

product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE <u>SR 3.7.3.1</u> REQUIREMENTS

> 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. [Systems with heaters must be operated for  $\geq$  10 continuous hours with the heaters energized. Systems without heaters need only be operated for  $\geq$  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.

#### <u>SR 3.7.3.2</u>

This SR verifies that the required CRFA testing is performed in accordance with the [Ventilation Filter Testing Program (VFTP)]. The [VFTP] includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the [VFTP].

#### <u>SR 3.7.3.3</u>

This SR verifies that each [CRFA] subsystem starts and operates on an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.7.1.5 overlaps this SR to provide complete testing of the safety function. The [18] month Frequency is specified in Reference 5.

#### <u>SR\_3.7.3.4</u>

This SR verifies the integrity of the control room enclosure and the assumed inleakage rates of potentially contaminated air. The control room positive pressure, with respect to potentially contaminated adjacent areas, is periodically tested to verify proper function of the [CRFA] System. During the emergency mode of operation, the [CRFA] System is designed to slightly pressurize the control room to [0.1] inches water

#### SURVEILLANCE REQUIREMENTS (continued)

gauge positive pressure with respect to adjacent areas to prevent unfiltered inleakage. The [CRFA] System is designed to maintain this positive pressure at a flow rate of [500] cfm to the control room in the isolation mode. The Frequency of [18] months on a STAGGERED TEST BASIS is consistent with industry practice and other filtration system SRs.

REFERENCES	1.	FSAR, Section [6.5.1].

- 2. FSAR, Section [9.4.1].
- 3. FSAR, Chapter [6].
- 4. FSAR, Chapter [15].
- 5. Regulatory Guide 1.52, Rev. [2].

#### **B 3.7 PLANT SYSTEMS**

#### B 3.7.4 [Control Room Air Conditioning (AC)] System

## BASES BACKGROUND The [Control Room AC] System provides temperature control for the control room following isolation of the control room. The [Control Room AC] System consists of two independent, redundant subsystems that provide cooling and heating of recirculated control room air. Each subsystem consists of heating coils, cooling coils, fans, chillers, compressors, ductwork, dampers, and instrumentation and controls to provide for control room temperature control. The [Control Room AC] System is designed to provide a controlled environment under both normal and accident conditions. A single subsystem provides the required temperature control to maintain a suitable control room environment for a sustained occupancy of 12 persons. The design conditions for the control room environment are 72°F and 50% relative humidity. The [Control Room AC] System operation in maintaining the control room temperature is discussed in the FSAR, Sections [6.4] and [9.4.1] (Refs. 1 and 2, respectively). The design basis of the [Control Room AC] System is to maintain the APPLICABLE control room temperature for a 30 day continuous occupancy. SAFETY **ANALYSES** The [Control Room AC] System components are arranged in redundant safety related subsystems. During emergency operation, the [Control Room ACI System maintains a habitable environment and ensures the OPERABILITY of components in the control room. A single active failure of a component of the [Control Room AC] System, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room temperature control. The [Control Room AC] System is designed in accordance with Seismic Category I requirements. The [Control Room AC] System is capable of removing sensible and latent heat loads from the control room, including consideration of equipment heat loads and personnel occupancy requirements to ensure equipment OPERABILITY. The [Control Room AC] System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES	
LCO	Two independent and redundant subsystems of the [Control Room AC] System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in the equipment operating temperature exceeding limits.
	The [Control Room AC] System is considered OPERABLE when the individual components necessary to maintain the control room temperature are OPERABLE in both subsystems. These components include the cooling coils, fans, chillers, compressors, ductwork, dampers, and associated instrumentation and controls.
APPLICABILITY	In MODE 1, 2, or 3, the [Control Room AC] System must be OPERABLE to ensure that the control room temperature will not exceed equipment OPERABILITY limits following control room isolation.
	In MODES 4 and 5, the probability and consequences of a Design Basis Accident are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the [Control Room AC] System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:
	<ul> <li>a. During operations with a potential for draining the reactor vessel (OPDRVs); and</li> </ul>
	b. During movement of [recently] irradiated fuel assemblies in the [primary or secondary containment]. [Due to radioactive decay, the Control Room AC System is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous [] (days).]
ACTIONS	<u>A.1</u>
	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 isolation, the consideration that the remaining subsystem can provide the required protection, and the availability of alternate cooling methods.

1.1.1

ACTIONS (continued)

#### B.1 and B.2

In MODE 1, 2, or 3, 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 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.

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

The Required Actions of Condition C are modified by a Note indicating that LCO 3.0.3 does not apply.

If moving [recently] irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of [recently] irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of [recently] irradiated fuel assemblies in the [primary or secondary containment] or during OPDRVs, if Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE [control room AC] subsystem may be placed immediately in operation. This action ensures that the remaining subsystem is OPERABLE, that no failures that would prevent actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, movement of [recently] 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.

#### ACTIONS (continued)

### <u>D.1</u>

If both [control room AC] subsystems are inoperable in MODE 1, 2, or 3, the [Control Room AC] System may not be capable of performing the intended function. Therefore, LCO 3.0.3 must be entered immediately.

#### E.1 and E.2

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

During movement of [recently] irradiated fuel assemblies in the [primary or secondary containment] or during OPDRVs with two [control room AC] subsystems inoperable, action must be taken to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, handling of [recently] irradiated fuel in the [primary or 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 <u>SF</u> REQUIREMENTS

#### <u>SR 3.7.4.1</u>

This SR verifies that the heat removal capability of the system is sufficient to remove the control room heat load assumed in the [safety analyses]. The SR consists of a combination of testing and calculation. The [18] month Frequency is appropriate since significant degradation of the [Control Room AC] System is not expected over this time period.

REFERENCES 1. FSAR, Section [6.4].

[Control Room AC] System B 3.7.4

BASES

REFERENCES (continued)

2. FSAR, Section [9.4.1].

# **B 3.7 PLANT SYSTEMS**

# B 3.7.5 Main Condenser Offgas

BASES	
BACKGROUND	During unit operation, steam from the low pressure turbine is exhausted directly into the condenser. Air and noncondensible gases are collected in the condenser, then exhausted through the steam jet air ejectors (SJAEs) to the Main Condenser Offgas System. The offgas from the main condenser normally includes radioactive gases.
	The Main Condenser Offgas System has been incorporated into the unit design to reduce the gaseous radwaste emission. This system uses a catalytic recombiner to recombine radiolytically dissociated hydrogen and oxygen. The gaseous mixture is cooled by the offgas condenser; the water and condensibles are stripped out by the offgas condenser and moisture separator. The radioactivity of the remaining gaseous mixture (i.e., the offgas recombiner effluent) is monitored downstream of the moisture separator prior to entering the holdup line.
APPLICABLE SAFETY ANALYSES	The main condenser offgas gross gamma activity rate is an initial condition of the Main Condenser Offgas System failure event as discussed in the FSAR, Section [15.7.1] (Ref. 1). The analysis assumes a gross failure in the Main Condenser Offgas System that results in the rupture of the Main Condenser Offgas System pressure boundary. The gross gamma activity rate is controlled to ensure that during the event, the calculated offsite doses will be well within the limits (NUREG-0800, Ref. 2) of 10 CFR 100 (Ref. 3), or the NRC staff approved licensing basis.
	The main condenser offgas limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	To ensure compliance with the assumptions of the Main Condenser Offgas System failure event (Ref. 1), the fission product release rate should be consistent with a noble gas release to the reactor coolant of 100 $\mu$ Ci/Mwt-second after decay of 30 minutes. The LCO is established consistent with this requirement ([3833] Mwt x 100 $\mu$ Ci/Mwt-second = [380] mCi/second).
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

# APPLICABILITY (continued)

A.1

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

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, B.3.1, and B.3.2

If the gross gamma activity 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 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.

#### SURVEILLANCE <u>SR 3.7.5.1</u> REQUIREMENTS

This SR, 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-85, Kr-87, and Kr-88. If the measured rate of radioactivity increases significantly (by  $\geq$  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, to ensure that the increase is not

# SURVEILLANCE REQUIREMENTS (continued)

indicative of a sustained increase in the radioactivity rate. The 31 day Frequency is adequate in view of other instrumentation that continuously monitor the offgas, and is acceptable based on operating experience.

This SR 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.

REFERENCES	1.	FSAR, Section [15.7.1].
	2.	NUREG-0800.
	3.	10 CFR 100.

#### **B 3.7 PLANT SYSTEMS**

#### B 3.7.6 Main Turbine Bypass System

#### BASES

#### BACKGROUND The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass capacity of the system is [35]% of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The Main Turbine Bypass System consists of a two valve chest connected to the main steam lines between the main steam isolation valves and the turbine stop valves. Each of these valves is sequentially operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Turbine Electro Hydraulic Control System, as discussed in the FSAR, Section [7.7.1.5] (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves, directing all steam flow to the turbine. If the speed governor or the load limiter restricts steam flow to the turbine, the pressure regulator controls the system pressure by opening the bypass valves. When the bypass valves open, the steam flows from the bypass chest, through connecting piping, to the pressure breakdown assemblies, where a series of orifices are used to further reduce the steam pressure before the steam enters the condenser. APPLICABLE The Main Turbine Bypass System is assumed to function during the SAFETY design basis feedwater controller failure, maximum demand event, **ANALYSES** described in the FSAR, Section [15.1.2] (Ref. 2). Opening the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MCPR during the event. An inoperable Main Turbine Bypass System may result in APLHGR and

The Main Turbine Bypass System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

MCPR penalties.

LCO

The Main Turbine Bypass System is required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause rapid pressurization, such that the Safety Limit MCPR is not exceeded. [With the Main Turbine Bypass System inoperable, modifications to the APLHGR limits (LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE

# BASES LCO (continued) (APLHGR)") and the MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") may be applied to allow continued operation.] An OF'ERABLE Main Turbine Bypass System requires the bypass valves to open in response to increasing main steam line pressure. This response is within the assumptions of the applicable analysis (Ref. 2). The APLHGR and MCPR limits for the inoperable Main Turbine Bypass System are specified in the COLR. APPLICABILITY The Main Turbine Bypass System is required to be OPERABLE at ≥ 25% RTP to ensure that the fuel cladding integrity Safety Limit and the cladding 1% plastic strain limit are not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases for LCO 3.2.1 and LCO 3.2.2, sufficient margin to these limits exists < 25% RTP. Therefore, these requirements are only necessary when operating at or above this power level. ACTIONS [A.1 If the Main Turbine Bypass System is inoperable (one or more bypass valves inoperable), or the APLHGR and MCPR limits for an inoperable Main Turbine Bypass System, as specified in the COLR, are not applied, the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status or adjust the APLHCIR and MCPR limits accordingly. The 2 hour Completion Time is reasonable, based on the time to complete the Required Action and the low probability of an event occurring during this period requiring the Main Turbine Bypass System. ] **B.1** If the Main Turbine Bypass System cannot be restored to OPERABLE status or the APLHGR and MCPR limits for an inoperable Main Turbine

Bypass System are not applied, THERMAL POWER must be reduced to < 25% RTP. As discussed in the Applicability section, operation at < 25% RTP results in sufficient margin to the required limits, and the Main Turbine Bypass System is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The 4 hour 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	<u>SR 3.7.6.1</u>
	Cycling each main turbine bypass valve through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. Therefore, the Frequency is acceptable from a reliability standpoint.
	<u>SR 3.7.6.2</u>
	The Main Turbine Bypass System is required to actuate automatically to perform its design function. This SR demonstrates that, with the required system initiation signals, the valves will actuate to their required position. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the [18] month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.
	<u>SR 3.7.6.3</u>
	This SR ensures that the TURBINE BYPASS SYSTEM RESPONSE TIME is in compliance with the assumptions of the appropriate safety analysis. The response time limits are specified in [unit specific documentation]. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the [18] month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.
REFERENCES	1. FSAR, Section [7.7.1.5].
	2. FSAR, Section [15.1.2].

#### **B 3.7 PLANT SYSTEMS**

#### B 3.7.7 Fuel Pool Water Level

BASES	
BACKGROUND	The minimum water level in the spent fuel storage pool and upper containment fuel storage pool meets the assumptions of iodine decontamination factors following a fuel handling accident.
	A general description of the spent fuel storage pool and upper containment fuel storage pool design is found in the FSAR, Section [9.1.2] (Ref. 1). The assumptions of the fuel handling accident are found in the FSAR, Sections [15.7.4] and [15.7.6] (Refs. 2 and 3, respectively).
APPLICABLE SAFETY ANALYSES	The water level above the irradiated fuel assemblies is an explicit assumption of the fuel handling accident. A fuel handling accident is evaluated to ensure that the radiological consequences (calculated whole body and thyroid doses at the exclusion area and low population zone boundaries) are $\leq 25\%$ (NUREG-0800, Section 15.7.4, Ref. 4) of the 10 CFR 100 (Ref. 5) exposure guidelines. A fuel handling accident could release a fraction of the fission product inventory by breaching the fuel rod cladding as discussed in the Regulatory Guide 1.25 (Ref. 6).
	The fuel handling accident is evaluated for the dropping of an irradiated fuel assembly onto stored fuel bundles. The consequences of a fuel handling accident inside the auxiliary building and inside containment are documented in References 2 and 3, respectively. The water levels in the spent fuel storage pool and upper containment fuel storage pool provide for absorption of water soluble fission product gases and transport delays of soluble and insoluble gases that must pass through the water before being released to the secondary containment atmosphere. This absorption and transport delay reduces the potential radioactivity of the release during a fuel handling accident.
	The fuel pool water level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The specified water level preserves the assumption of the fuel handling accident analysis (Refs. 2 and 3). As such, it is the minimum required for fuel movement within the spent fuel storage pool and upper containment

fuel storage pool.

#### Fuel Pool Water Level B 3.7.7

BASES	
APPLICABILITY	This LCO applies whenever movement of irradiated fuel assemblies occurs in the associated fuel storage racks since the potential for a release of fission products exists.
ACTIONS	<u>A.1</u>
	Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. 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 a sufficient reason to require a reactor shutdown.
	When the initial conditions for an accident cannot be met, steps should be taken to preclude the accident from occurring. With either fuel pool level less than required, the movement of irradiated fuel assemblies in the associated storage pool is suspended immediately. Suspension of this activity shall not preclude completion of movement of an irradiated fuel assembly to a safe position. This effectively precludes a spent fuel handling accident from occurring.
SURVEILLANCE REQUIREMENTS	<u>SR 3.7.7.1</u>
	This SR verifies that sufficient water is available in the event of a fuel handling accident. The water level in the spent fuel storage pool and upper containment fuel storage racks must be checked periodically. The 7 day Frequency is acceptable, based on operating experience, considering that the water volume in the pool is normally stable and water level changes are controlled by unit procedures.
REFERENCES	1. FSAR, Section [9.1.2].
	2. FSAR, Section [15.7.4].
	3. FSAR, Section [15.7.6].
	4. NUREG-0800, Section 15.7.4, Revision 1, July 1981.
	5. Regulatory Guide 1.52, Rev. [2].
	6. Regulatory Guide 1.25, March 1972.

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#### B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources - Operating

#### BASES

BACKGROUND The unit Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources and the onsite standby power sources (diesel generators (DGs) 2A, 2C, and 1B). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E 4.16 kV ESF bus (refer to LCO 3.8.9, "Distribution Systems - Operating"). Each ESF bus has three separate and independent offsite sources of power. Each ESF bus has a dedicated onsite DG. The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition.

Offsite power is supplied to the switchyard from the transmission network. From the switchyard two electrically and physically separated circuits provide AC power to each 4.16 kV ESF bus. A 115 kV power source provides a third completely independent circuit. The offsite AC electrical power sources are designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A detailed description of the offsite power network and circuits to the onsite Class 1E [ESF buses] is found in FSAR, Chapter [8] (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the [onsite Class 1E ESF bus(es)].

Certain required plant loads are returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Class 1E Distribution System. Within [1 minute] after the initiating signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service via the load sequencer.

# BACKGROUND (continued)

	The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. A DG starts automatically on loss of coolant accident (LOCA) signal (i.e., low reactor water level signal or high drywell pressure signal) or on an ESF bus degraded voltage or undervoltage signal (refer to LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation").
	In the event of a loss of preferred power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a LOCA.
	Certain required plant loads are returned to service in a predetermined sequence in order to prevent overloading the DG. For Divisions 1 and 2, the automatic diesel start and the power from normal to emergency power supplies is controlled by the Load Shedding and Sequencing (LSS) System. The LSS circuits actuate on loss of offsite power or LOCA signal. The system starts the DGs and, if an undervoltage exists on a Division 1 or 2 bus, it sheds nonvital loads from the affected bus and then sequentially starts the vital loads. The Division 3 bus has no shedding or sequencing.
	Ratings for DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating is 7000 kW for Divisions 1 and 2 and is 3300 kW for Division 3, with 10% overload permissible for up to 2 hours in any 24 hour period.
APPLICABLE SAFETY ANALYSES	The initial conditions of DBA and transient analyses in the FSAR, Chapter [6] (Ref. 4) and Chapter [15] (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.
	The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

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a. An assumed loss of all offsite power or all onsite AC power and

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#### APPLICABLE SAFETY ANALYSES (continued)

b. A worst case single failure.

AC sources satisfy the requirements of Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Distribution System, and three separate and independent DGs (11, 12, and 13), ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Qualified offsite circuits are those that are described in the FSAR and are part of the licensing basis for the unit.

[In addition, [one required automatic load sequencer per ESF bus] shall be OPERABLE. In general, Division 3 does not have a load sequencer since it has only one large load (i.e., the high pressure core spray (HPCS) pump). In such cases the LCO should refer to the Division 1 and 2 sequencers only.]

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses. Each offsite circuit consists of incoming breaker and disconnect to the respective service transformers 11 and 21, the 11 and 21 service transformers, the ESF transformers 11 and 21, and the respective circuit path including feeder breakers to the 4.16 kV ESF buses.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with engine hot and DG in standby with engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

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BASES	
LCO (continued)	
	The AC sources in one division must be separate and independent (to the extent possible) of the AC sources in the other division(s). For the DGs, the separation and independence are complete. For the offsite AC sources, the separation and independence are to the extent practical.
APPLICABILITY	The AC sources and sequencers are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:
	<ul> <li>Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients and</li> </ul>
	<ul> <li>Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.</li> </ul>
	A Note has been added taking exception to the Applicability requirements for Division 3 sources, provided the HPCS System is declared inoperable. This exception is intended to allow declaring of the Division 3 inoperable either in lieu of declaring the Division 3 source inoperable, or at any time subsequent to entering ACTIONS for an inoperable Division 3 source. This exception is acceptable since, with the Division 3 inoperable and the associated ACTIONS entered, the Division 3 AC sources provide no additional assurance of meeting the above criteria.
	AC power requirements for MODES 4 and 5 are covered in LCO 3.8.2, "AC Sources - Shutdown."
ACTIONS	<u>A.1</u>
	To ensure a highly reliable power source remains, it is necessary to verify the availability of the remaining required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in the Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.
	<u>A.2</u>
	Required Action A.2, which only applies if the division cannot be powered from an offsite source, is intended to provide assurance that an event

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#### ACTIONS (continued)

with a coincident single failure of the associated DG does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included, although, for this Required Action, Division 3 is considered redundant to Division 1 and 2 Emergency Core Cooling Systems (ECCS)). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has no offsite power.

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

- a. The division has no offsite power supplying its loads and
- b. A required feature on the other division is inoperable.

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

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

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection may have been lost for the required feature's function; however, function is not lost. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

#### ACTIONS (continued)

#### <u>A.3</u>

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours.

This Completion Time assumes sufficient offsite power remains to power the minimum loads needed to respond to analyzed events. In the event more than one division is without offsite power, this assumption is not met. Therefore, the optional Completion Time is specified. Should two or more divisions be affected, the 24 hour Completion Time is conservative with respect to the Regulatory Guide assumptions supporting a 24 hour Completion Time for both offsite circuits inoperable. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E distribution system.

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

The third Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the

#### ACTIONS (continued)

LCO was initially not met, instead of at the time that Condition A was entered.

#### <u>B.1</u>

To ensure a highly reliable power source remains, it is necessary to verify the availability of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

#### <u>B.2</u>

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included, although, for this Required Action, Division 3 is considered redundant to Division 1 and 2 Emergency Core Cooling Systems (ECCS)). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

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

- a. An inoperable DG exists and
- b. A required feature on another division is inoperable.

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

Discovering one required DG inoperable coincident with one or more required support or supported features, or both, that are associated with the OPERABLE DG(s), results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing

#### ACTIONS (continued)

concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

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

#### B.3.1 and B.3.2

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

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

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

### <u>B.4</u>

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition B for a period that should not exceed 72 hours. In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. The

#### ACTIONS (continued)

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

The second Completion Time for Required Action B.4 established a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

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

#### C.1 and C.2

Required Action C.1 addresses actions to be taken in the event of concurrent failure of redundant required features. Required Action C.1 reduces the vulnerability to a loss of function. The Completion Time for taking these actions is reduced to 12 hours from that allowed with only one division without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety divisions are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are designed with redundant safety related divisions (i.e., single division systems are not included in the list, although, for this Required Action, Division 3 is considered redundant to Division 1 and 2 ECCS). Redundant required features

#### ACTIONS (continued)

failures consist of any of these features that are inoperable, because any inoperability is on a division redundant to a division with inoperable offsite circuits.

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. All required offsite circuits are inoperable and

b. A required feature is inoperable.

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

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this degradation level:

- a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure and
- b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC

#### ACTIONS (continued)

sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Regulatory Guide 1.93 (Ref. 6), with the available offsite AC sources two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

#### D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to any division, Actions for LCO 3.8.9, "Distribution Systems -Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of the offsite circuit and one DG without regard to whether a division is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized division.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours. In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

### <u>E.1</u>

With two DGs inoperable, there is one remaining standby AC source. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of

#### ACTIONS (continued)

AC power for the majority of ESF equipment at this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to 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.

# [<u>F.1</u>

The sequencer(s) is an essential support system to [both the offsite circuit and the DG associated with a given ESF bus.] [Furthermore, the sequencer(s) is on the primary success path for most major AC electrically powered safety systems powered from the associated ESF bus.] Therefore, loss of an [ESF bus's sequencer] affects every major ESF system in the [division]. The [12] hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining sequencer OPERABILITY. This time period also ensures that the probability of an accident requiring sequencer OPERABILITY occurring during periods when the sequencer is inoperable is minimal.

This Condition is preceded by a Note that allows the Condition to be deleted if the plant design is such that any sequencer failure mode only affects the ability of the associated DG to power its respective safety

#### ACTIONS (continued)

loads under any conditions. Implicit in this Note is the concept that the Condition must be retained if any sequencer failure mode results in the inability to start all or part of the safety loads when required, regardless of power availability, or results in overloading the offsite power circuit to a safety bus during an event thereby causing its failure. Also implicit in the Note is the concept that the Condition is not applicable to any Division that does not have a sequencer [Division 3 does not normally have a sequencer in the circuitry].

#### G.1 and G.2

If the inoperable AC electrical power sources [and sequencers] 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 unit must be brought to 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.

#### <u>H.1</u>

Condition H 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.

#### SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection andtesting of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, GDC 18 (Ref. 8). Periodic component tests are supplemented by extensive functional tests during refueling outages under simulated accident conditions. The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3), Regulatory Guide 1.108 (Ref. 9), and Regulatory Guide 1.137 (Ref. 10).

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of [3740] V is 90% of the nominal 4160 V output voltage. This value, which is specified in ANSI C84.1 (Ref. 11), allows for voltage drop to the terminals of 4000 V motors whose minimum operating

# SURVEILLANCE REQUIREMENTS (continued)

voltage is specified as 90%, or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of [9756] V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to  $\pm 2\%$  of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

#### <u>SR 3.8.1.1</u>

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 (Note 1 for SR 3.8.1.2 and Note for SR 3.8.1.7) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

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

[In order to reduce stress and wear on diesel engines, some manufacturers recommend that the starting speed of DGs be limited, that

#### SURVEILLANCE REQUIREMENTS (continued)

warmup be limited to this lower speed, and that DGs be gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 2, which is only applicable when such procedures are recommended by the manufacturer. ]

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 10 seconds. The 10 second start requirement supports the assumptions in the design basis LOCA analysis (Ref. 10). The 10 second start requirement may not be applicable to SR 3.8.1.2 (see Note 2 of SR 3.8.1.2), when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies. Since SR 3.8.1.7 does require a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2.

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.

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

#### SR 3.8.1.3

This Surveillance demonstrates that the DGs are capable of synchronizing and accepting greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

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 load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

# SURVEILLANCE REQUIREMENTS (continued)

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

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 must 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.

#### <u>SR 3.8.1.4</u>

This SIR provides verification that the level of fuel oil in the day tank [and engine mounted tank] is at or above the level at which fuel oil is automatically added. 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 full load plus 10%.

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

#### SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day [and engine mounted] tanks once every [31] days eliminates the necessary environment for bacterial survival. This is most effective means in controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal
#### SURVEILLANCE REQUIREMENTS (continued)

of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 10). This SR is for 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 Frequency for this SR is variable, depending on individual system design, with up to a 92 day interval. The 92 day Frequency corresponds to the testing requirements for pumps as contained in the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 12); however, the design of fuel transfer systems is such that pumps operate automatically or must be started manually in order to maintain an adequate volume of fuel oil in the day [and engine mounted] tanks during or following DG testing. In such a case, a 31 day Frequency is appropriate. Since proper operation of fuel transfer systems is an inherent part of DG OPERABILITY, the Frequency of this SR should be modified to reflect individual designs. ]

<u>SR 3.8.1.7</u>

See SR 3.8.1.2.

#### [<u>SR 3.8.1.8</u>

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The [18 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 when performed on the [18 month]

# SURVEILLANCE REQUIREMENTS (continued)

Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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

#### <u>SR\_3.8.1.9</u>

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The load referenced for DG 11 is the 1200 kW low pressure core spray pump; for DG 12, the 550 kW residual heat removal (RHR) pump; and for DG 13 the 2180 kW HPCS pump. The Standby Service Water (SSW) pump values are not used as the largest load since the SSW supplies cooling to the associated DG. If this load were to trip, it would result in the loss of the DG. This Surveillance may be accomplished by either:

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

#### SURVEILLANCE REQUIREMENTS (continued)

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

As required by IEEE-308 (Ref. 13), 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. For the Grand Gulf Nuclear Station these values are the same.

The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The 3 seconds specified is equal to 60% of the 5 second load sequence interval associated with sequencing of this largest load. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are steady state voltage and frequency values to which the system must recover following load rejection. The [18 month] Frequency is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 9).

This SR has been modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated **OPERABILITY** concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Note 2 ensures that the DG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a power

# SURVEILLANCE REQUIREMENTS (continued)

factor of  $\leq$  [0.9]. This power factor is representative of the actual inductive loading a DG would see under design basis accident conditions. Under certain conditions, however, Note 2 allows the surveillance to be conducted at a power factor other than  $\leq$  [0.9]. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to  $\leq$  [0.9] results in voltages on the emergency busses that are too high. Under these conditions, the power factor should be maintained as close as practicable to [0.9] while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the DC excitation levels needed to obtain a power factor of [0.9] may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the DC. In such cases, the power factor shall be maintained as close as practicable to [0.9] without exceeding the DG excitation limits.

#### - REVIEWER'S NOTE -

The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:

- a. Performance of the SR will not render any safety system or component inoperable,
- b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems, and
- c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

#### <u>SR 3.8.1.10</u>

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage

# SURVEILLANCE REQUIREMENTS (continued)

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

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

The [18 month] Frequency is consistent with the recommendation of Regulatory Guide 1.108 (Ref. 9) and is intended to be consistent with expected fuel cycle lengths.

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

#### - REVIEWER'S NOTE -

The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:

#### SURVEILLANCE REQUIREMENTS (continued)

- a. Performance of the SR will not render any safety system or component inoperable,
- b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems, and
- c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

#### <u>SR 3.8.1.11</u>

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

The DG auto-start time of 10 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.

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 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 [18 months] is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(1), takes into

#### SURVEILLANCE REQUIREMENTS (continued)

consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing. the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations for [Division 1 and 2] DGs. [For the [Division 3] DG, standby conditions mean that the lube oil is heated and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by the lubricating oil and circulates through the system by natural circulation.] 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. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment.

#### [<u>SR 3.8.1.12</u>

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time ([10] seconds) from the design basis actuation signal (LOCA signal) and operates for  $\geq$  [5] minutes. The [5] minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and SR 3.8.1.12.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on an ECCS signal without loss of offsite power.

# SURVEILLANCE REQUIREMENTS (continued)

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the loading logic for loading onto offsite power. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, high pressure injection systems are not capable of being operated at full flow, or 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 [18 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 when performed at the [18 month] Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for the Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. 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. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a

#### SURVEILLANCE REQUIREMENTS (continued)

plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment. ]

#### SR 3.8.1.13

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

The [18 month] Frequency is based on engineering judgment, taking into consideration 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 when performed at the [18 month] Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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

#### SURVEILLANCE REQUIREMENTS (continued)

#### - REVIEWER'S NOTE -

The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:

- a. Performance of the SR will not render any safety system or component inoperable,
- b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems, and
- c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

#### SR 3.8.1.14

Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(3), requires demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours - 22 hours of which is at a load equivalent to the continuous rating of the DG, and 2 hours of which is at a load equivalent to 110% of the continuous duty rating of the DG. 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  $\leq$  [0.9]. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

The [18 month] Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(3); 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 three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in

#### SURVEILLANCE REQUIREMENTS (continued)

accordance with vendor recommendations in order to maintain DG OPERABILITY. Similarly, momentary power factor transients above the limit do not invalidate the test. 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 would challenge continued steady state operation and, as a result, plant safety systems. Note 3 ensures that the DG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a power factor of  $\leq$  [0.9]. This power factor is representative of the actual inductive loading a DG would see under design basis accident conditions. Under certain conditions, however, Note 3 allows the surveillance to be conducted at a power factor other than  $\leq$  [0.9]. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to  $\leq$  [0.9] results in voltages on the emergency busses that are too high. Under these conditions, the power factor should be maintained as close as practicable to [0.9] while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the DG excitation levels needed to obtain a power factor of [0.9] may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the DG. In such cases, the power factor shall be maintained as close as practicable to [0.9] without exceeding the DG excitation limits. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

#### SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal

#### SURVEILLANCE REQUIREMENTS (continued)

Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA.

The [18 month] Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(5).

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 prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. 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.

#### <u>SR 3.8.1.16</u>

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), this Surveillance ensures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the auto-start logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and the load sequence timers are reset.

The Frequency of [18 months] is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.1.(6), and takes into consideration plant conditions required to perform the Surveillance.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated

#### SURVEILLANCE REQUIREMENTS (continued)

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

#### SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. 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. 13), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.12. The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading 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 [18 month] Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(8); 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 reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to

#### SURVEILLANCE REQUIREMENTS (continued)

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

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## <u>SR 3.8.1.18</u>

Under accident conditions [and loss of offsite power] loads are sequentially connected to the bus by the load sequencing panel. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The [10]% load sequence time interval tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of [18 months] is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(2); 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 would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and

#### SURVEILLANCE REQUIREMENTS (continued)

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

#### - REVIEWER'S NOTE -

The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:

- a. Performance of the SR will not render any safety system or component inoperable,
- b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems, and
- c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

#### SR 3.8.1.19

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

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

# SURVEILLANCE REQUIREMENTS (continued)

The Frequency of [18 months] takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of [18 months].

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

#### <u>SR 3.8.1.20</u>

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

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9).

This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant

# SURVEILLANCE REQUIREMENTS (continued)

and oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

- REFERENCES 1. 10 CFR 50, Appendix A, GDC 17.
  - 2. FSAR, Chapter [8].
  - 3. Regulatory Guide 1.9.
  - 4. FSAR, Chapter [6].
  - 5. FSAR, Chapter [15].
  - 6. Regulatory Guide 1.93.
  - 7. Generic Letter 84-15, July 2, 1984.
  - 8. 10 CFR 50, Appendix A, GDC 18.
  - 9. Regulatory Guide 1.108.
  - 10. Regulatory Guide 1.137.
  - 11. ANSI C84.1, 1982.
  - 12. ASME, Boiler and Pressure Vessel Code, Section XI.
  - 13. IEEE Standard 308.

#### B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources - Shutdown

#### BASES

A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources - Operating."
The OPERABILITY of the minimum AC sources during MODES 4 and 5 and during movement of [recently] irradiated fuel assemblies ensures that:
a. The unit can be maintained in the shutdown or refueling condition for extended periods,
<ul> <li>Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status, and</li> </ul>
c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident [involving handling recently irradiated fuel. Due to radioactive decay, AC electrical power is only required to mitigate fuel handling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous [] days)].
In general, when the unit is shut down the Technical Specifications (TS) requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or loss of all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, and 3 have no specific analyses in MODES 4 and 5. Worst case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence significantly reduced or eliminated, and minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

During MODES 1, 2, and 3, various deviations from the analysis assumptions and design requirements are allowed within the ACTIONS. This allowance is in recognition that certain testing and

# APPLICABLE SAFETY ANALYSES (continued)

maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 4 and 5, performance of a significant number of required testing and maintenance activities is also required. In MODES 4 and 5, the activities are generally planned and administratively controlled. Relaxations from typical MODE 1, 2, and 3 LCO requirements are acceptable during shutdown MODES based on:

- a. The fact that time in an outage is limited. This is a risk prudent goal as well as utility economic consideration.
- b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.
- c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.
- d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, and 3 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability of supporting systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite (diesel generator (DG)) power.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO One offsite circuit capable of supplying onsite Class 1E power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems - Shutdown," ensures that all required Division 1 loads, Division 2 loads, or both, are powered from offsite power. An OPERABLE DG, associated with a Division 1 or Division 2 Distribution System Engineered Safety Feature (ESF) bus required OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Similarly, when the high pressure core spray (HPCS) is required to be OPERABLE, a separate offsite circuit to the Division 3 Class 1E onsite electrical power distribution subsystem, or an OPERABLE Division 3 DG, ensures an additional source of power for the HPCS. This additional source for Division 3 is not necessarily required to be connected to be OPERABLE. Either the circuit required by LCO Item a., or a circuit required to meet LCO Item c. may be connected, with the

#### LCO (continued)

second source available for connection. Together, OPERABILITY of the required offsite circuit(s) and DG(s) ensure the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents [involving handling recently irradiated fuel], reactor vessel draindown). Automatic initiation of the required DG during shutdown conditions is specified in LCO 3.3.5.1, ECCS Instrumentation, and LCO 3.3.8.1, LOP Instrumentation.

The qualified offsite circuit(s) must be capable of maintaining rated frequency and voltage while connected to their respective ESF bus(es), and of accepting required loads during an accident. Qualified offsite circuits are those that are described in the FSAR and are part of the licensing basis for the plant. [The offsite circuit consists of incoming breaker and disconnect to the respective service transformers 11 and 21, the 11 and 21 service transformers, the ESF transformers 11 and 21, and the respective circuit path including feeder breakers to all 4.16 kV ESF buses required by LCO 3.8.10.]

The required DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage, and accepting required loads. This sequence must be accomplished within [10] seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as: DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY. [In addition, proper sequencer operation is an integral part of offsite circuit OPERABILITY since its inoperability impacts on the ability to start and maintain energized loads required OPERABLE by LCO 3.8.10.]

It is acceptable for divisions to be cross tied during shutdown conditions, permitting a single offsite power circuit to supply all required divisions. [No fast transfer capability is required for offsite circuits to be considered OPERABLE.]

# BASES LCO (continued) As described in Applicable Safety Analyses, in the event of an accident during shutdown, the TS are designed to maintain the plant in a condition such that, even with a single failure, the plant will not be in immediate difficulty. **APPLICABILITY** The AC sources required to be OPERABLE in MODES 4 and 5 and during movement of [recently] irradiated fuel assemblies in the [primary or secondary] containment provide assurance that: Systems to provide adequate coolant inventory makeup are а. available for the irradiated fuel in the core in case of an inadvertent draindown of the reactor vessel. Systems needed to mitigate a fuel handling accident [involving b. handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous [ ] days)] are available, C. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available, and **d**. Instrumentation and control capability is available for monitoring and rnaintaining the unit in a cold shutdown condition or refueling condition. The AC power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.1. **ACTIONS** LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS 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 irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, or 3 would require the unit to be shutdown unnecessarily. <u>A.1</u> An offsite circuit is considered inoperable if it is not available to one required ESF division. If two or more ESF 4.16 kV buses are required per LCO 3.8.10, division(s) with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE

#### ACTIONS (continued)

ALTERATIONS, [recently] irradiated fuel movement, and operations with a potential for draining the reactor vessel. By the allowance of the option to declare required features inoperable with no offsite power available, appropriate restrictions can be implemented in accordance with the affected required feature(s) LCOs' ACTIONS.

# A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4

With the offsite circuit not available to all required divisions, the option still exists to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required DG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of [recently] irradiated fuel assemblies in the [primary or secondary containment], and activities that could potentially result in inadvertent draining of the reactor vessel.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events. It is further required to initiate action immediately to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System ACTIONS are not entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A have been modified by a Note to indicate that when Condition A is entered with no AC power to any required ESF bus, ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit whether or not a division is de-energized. LCO 3.8.10 provides the appropriate restrictions for the situation involving a de-energized division.

#### ACTIONS (continued)

#### <u>C.1</u>

When the HPCS is required to be OPERABLE, and the additional required Division 3 AC source is inoperable, the required diversity of AC power sources to the HPCS is not available. Since these sources only affect the HPCS, the HPCS is declared inoperable and the Required Actions of the affected Emergency Core Cooling Systems LCO entered.

In the event all sources of power to Division 3 are lost, Condition A will also be entered and direct that the ACTIONS of LCO 3.8.10 be taken. If only the Division 3 additional required AC source is inoperable, and power is still supplied to HPCS, 72 hours is allowed to restore the additional required AC source to OPERABLE. This is reasonable considering HPCS will still perform its function, absent an additional single failure.

#### SURVEILLANCE REQUIREMENTS

# <u>SR\_3.8.2.1</u>

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, and 3. SR 3.8.1.8 is not required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.17 is not required to be met because the required OPERABLE DG(s) is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.20 is excepted because starting independence is not required with the DG(s) that is not required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

This SR is modified by two Notes. The reason for Note 1 is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during the performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG, and to preclude deenergizing a required 4160 V ESF bus or disconnecting a required offsite circuit during performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit is required to be OPERABLE. Note 2 states that SRs 3.8.1.12 and 3.8.1.19 are not required to be met when its associated ECCS subsystem(s) are not required to be OPERABLE. These SRs demonstrate the DG response to an ECCS signal (either alone or in conjunction with a loss-of-power signal). This is consistent with the ECCS instrumentation requirements

# SURVEILLANCE REQUIREMENTS (continued)

that do not require the ECCS signals when the ECCS System is not required to be OPERABLE per LCO 3.5.2, "ECCS-Shutdown."

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REFERENCES None.

## B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

#### BASES

BACKGROUND Each diesel generator (DG) is provided with a storage tank having a fuel oil capacity sufficient to operate that DG for a period of 7 days while the DG is supplying maximum post loss of coolant accident load demand (Ref. 1). The maximum load demand is calculated using the assumption that at least two DGs are available. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources.

> Fuel oil is transferred from each storage tank to its respective day tank by a transfer pump associated with each storage tank. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve, or tank to result in the loss of more than one DG. All outside tanks, pumps, and piping are located underground. The fuel oil level in the storage tank is indicated in the control room.

> For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 3). The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity), and impurity level.

The DG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. Each engine oil sump contains an inventory capable of supporting a minimum of [7] days of operation. [The onsite storage in addition to the engine oil sump is sufficient to ensure 7 days continuous operation.] This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Each DG has an air start system with adequate capacity for five successive start attempts on the DG without recharging the air start receiver(s).

Diesel Fuel Oil, Lube Oil, and Starting Air B 3.8.3

BASES		
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in FSAR, Chapter [6] (Ref. 4) and Chapter [15] (Ref. 5), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, reactor coolant system, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.	
	Since diesel fuel oil, lube oil, and starting air subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).	
LCO	Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. Additionally, sufficient lube oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources - Shutdown."	
	successive DG start attempts without recharging the air start receivers.	
APPLICABILITY	The AC sources, LCO 3.8.1 and LCO 3.8.2, are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil, lube oil, and starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated DG is required to be OPERABLE.	
ACTIONS	The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued	

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#### ACTIONS (continued)

operation, and subsequent inoperable DG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

# <u>A.1</u>

In this Condition, the 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events such as either:

- a. Full load operation required after an inadvertent start while at minimum required level or
- b. Feed and bleed operations that may be necessitated by increasing particulate levels or any number of other oil quality degradations.

This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of the fuel oil to the tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

#### <u>B.1</u>

With lube oil inventory < 500 gal, sufficient lube oil to support 7 days of continuous DG operation at full load conditions may not be available. However, the Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply. This restriction allows sufficient time for obtaining the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

# <u>C.1</u>

This Condition is entered as a result of a failure to meet the acceptance criterion for particulates. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling),

#### ACTIONS (continued)

contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulate does not mean failure of the fuel oil to burn properly in the diesel engine, since particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and since proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The 7 day Completion Time allows for further evaluation, resampling, and re-analysis of the DG fuel oil.

# <u>D.1</u>

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or a combination of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outsicle limits, there is high likelihood that the DG would still be capable of performing its intended function.

# <u>E.1</u>

With starting air receiver pressure < [225] psig, sufficient capacity for five successive DG start attempts does not exist. However, as long as the receiver pressure is > [125] psig, there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

# <u>F.1</u>

With a Required Action and associated Completion Time not met, or the stored diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through E, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

#### SURVEILLANCE <u>SR 3.8.3.1</u> REQUIREMENTS

This SR provides verification that there is an adequate inventory of fuel oil in the storage tanks to support each DG's operation for 7 days at full load. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The 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.

#### SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of full load operation for each DG. The 500 gal 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 full 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.

#### SR 3.8.3.3

The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion 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 receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

- a. Sample the new fuel oil in accordance with ASTM D4057-[ ] (Ref. 6),
- b. Verify in accordance with the tests specified in ASTM D975-[ ] (Ref. 6) that the sample has an absolute specific gravity at 60/60°F

Diesel Fuel Oil, Lube Oil, and Starting Air B 3.8.3

#### BASES

# SURVEILLANCE REQUIREMENTS (continued)

of  $\geq$  0.83 and  $\leq$  0.89 (or an API gravity at 60°F of  $\geq$  27° and  $\leq$  39°), a kinematic viscosity at 40°C of  $\geq$  1.9 centistokes and  $\leq$  4.1 centistokes, and a flash point of  $\geq$  125°F, and

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-[ ] (Ref. 6).

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO since the fuel oil is not added to the storage tanks.

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-[] (Ref. 6) are met for new fuel oil when tested in accordance with ASTM D975-[] (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D1522-[] (Ref. 6) or ASTM D2622-[] (Ref. 6). The 31 day period is acceptable because the fuel oil properties of interest, even if not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

Fuel oil degradation during long term storage shows up as an increase in particulate, mostly due to oxidation. The presence of particulate does not mean that the fuel oil will not burn properly in a diesel engine. However, the particulate can cause fouling of filters and fuel oil injection equipment, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D2276-[ ], Method A (Ref. 6). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. [For those designs in which the total volume of stored fuel oil is contained in two or more interconnected tanks, each tank must be considered and tested separately.]

The Frequency of this Surveillance takes into consideration fuel oil degradation trends indicating that particulate concentration is unlikely to change between Frequency intervals.

#### SURVEILLANCE REQUIREMENTS (continued)

#### <u>SR 3.8.3.4</u>

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of five engine start cycles without recharging. [A start cycle is defined by the DG vendor, but usually is measured in terms of time (seconds of cranking) or engine cranking speed.] The pressure specified in this SR is intended to reflect the lowest value at which the [five] starts can be accomplished.

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

#### SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the storage tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 2). 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 the Surveillance.

- REFERENCES 1. FSAR, Section [9.5.4].
  - 2. Regulatory Guide 1.137.
  - 3. ANSI N195, Appendix B, 1976.
  - 4. FSAR, Chapter [6].
  - 5. FSAR, Chapter [15].

Diesel Fuel Oil, Lube Oil, and Starting Air B 3.8.3

BASES

# REFERENCES (continued)

6. ASTM Standards: D4057-[ ], D975-[ ], D4176-[ ], D1552-[ ], D2622-[ ], and D2276-[ ], Method A.

#### B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources - Operating

#### BASES

BACKGROUND The station DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment. As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC electrical power system also conforms to the requirements of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

> The 125 VDC electrical power system consists of three independent Class 1E DC electrical power subsystems, Divisions 1, 2, and 3. Each subsystem consists of a battery, associated battery charger(s), and all the associated control equipment and interconnecting cabling.

During normal operation, the DC loads are powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC loads are automatically powered from the Engineered Safety Feature (ESF) batteries.

Each of the Division 1 and 2 electrical power subsystems provides the control power for its associated Class 1E AC power load group, 4.16 kV switchgear, and 480 V load centers. Also, these DC subsystems provide DC electrical power to the inverters, which in turn power the AC vital buses. The Division 3 DC electrical power subsystem provides DC motive and control power as required for the High Pressure Core Spray (HPCS) System diesel generator (DG) set control and protection.

The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution Systems - Operating," and LCO 3.8.10, "Distribution Systems - Shutdown."

Each DC battery subsystem is separately housed in a ventilated room apart from its charger and distribution centers. Each subsystem is located in an area separated physically and electrically from the other subsystems to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E subsystems such as batteries, battery chargers, or distribution panels.

#### BACKGROUND (continued)

Each Division 1 and 2 battery has adequate storage capacity to meet the duty cycle(s) discussed in the FSAR, Chapter [8] (Ref. 4). The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors. The Division 3 battery has adequate storage to meet the duty cycle(s) discussed in the FSAR, Chapter [8] (Ref. 4). The battery is designed with additional capacity above that required by the design duty cycle (s) discussed in the FSAR, Chapter [8] (Ref. 4). The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors.

The batteries for a DC electrical power subsystem are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. The minimum design voltage limit is 105/210 V.

The battery cells are of flooded lead acid construction with a nominal specific gravity of [1.215]. This specific gravity corresponds to an open circuit battery voltage of approximately 120 V for a [58] cell battery (i.e., cell voltage of [2.065] volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage  $\geq$  [2.0654] Vpc, the battery cell will maintain its capacity for [30] days without further charging per manufacturer's instructions. Optimal long term performance however, is obtained by maintaining a float voltage [2.20 to 2.25] Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge. The nominal float voltage of [2.22] Vpc corresponds to a total float voltage output of [128.8] V for a [58] cell battery as discussed in the FSAR, Chapter [8] (Ref. 4).

Each battery charger of Division 1 and 2 DC electrical power subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger has sufficient excess capacity to restore the battery bank from the design minimum charge to its fully charged state within 12 hours while supplying normal steady state loads (Ref. 4).

The battery charger of Division 3 DC electrical power subsystem has sufficient excess capacity to restore the battery bank from the design minimum charge to its fully charged state in 8 hours while supplying normal steady state loads (Ref. 4).

The battery charger is normally in the float-charge mode. Float-charge is the condition in which the charger is supplying the connected loads and

#### BACKGROUND (continued)

the battery cells are receiving adequate current to optimally charge the battery. This assures the internal losses of a battery are overcome and the battery is maintained in a fully charged state.

When desired, the charger can be placed in the equalize mode. The equalize mode is at a higher voltage than the float mode and charging current is correspondingly higher. The battery charger is operated in the equalize mode after a battery discharge or for routine maintenance. Following a battery discharge, the battery recharge characteristic accepts current at the current limit of the battery charger (if the discharge was significant, e.g., following a battery service test) until the battery terminal voltage approaches the charger voltage setpoint. Charging current then reduces exponentially during the remainder of the recharge cycle. Lead-calcium batteries have recharge efficiencies of greater than 95%, so once at least 105% of the ampere-hours discharged have been returned, the battery capacity would be restored to the same condition as it was prior to the discharge. This can be monitored by direct observation of the exponentially decaying charging current or by evaluating the amp-hours discharged from the battery and amp-hours returned to the battery.

# APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter [6] (Ref. 5) and Chapter [15] (Ref. 6), assume that ESF systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining DC sources OPERABLE during accident conditions in the event of:

- a. An assumed loss of all offsite AC power or of all onsite AC power and
- b. A worst case single failure.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO The DC electrical power subsystems, each subsystem consisting of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within

BASES	
LCO (continued)	
	the divisions, are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).
APPLICABILITY	The DC electrical power sources are required to be OPERABLE in MODIES 1, 2, and 3 to ensure safe unit operation and to ensure that:
	<ul> <li>Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients and</li> </ul>
	b. Adequate core cooling is provided, and containment integrity and other vital functions are maintained in the event of a postulated DBA.
	The DC electrical power requirements for MODES 4 and 5 are addressed in the Bases for LCO 3.8.5, "DC Sources - Shutdown."
ACTIONS	A.1, A.2, and A.3
	Condition A represents one division with one [or two] battery chargers inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Required Action A.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provicles for returning the inoperable charger to OPERABLE status or provides for returning the inoperable charger to OPERABLE status or provides for returning the inoperable charger to OPERABLE status or provides for returning the inoperable charger to the minimum established float voltage to greater than or equal to the minimum established float voltage provides good assurance that, within [12] hours, the battery will be restored to its fully charged condition (Required Action A.2) from any discharge that might have occurred due to the charger inoperability.

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ACTIONS (continued)

#### - REVIEWER'S NOTE -

A plant that cannot meet the 12-hour Completion Time due to an inherent battery charging characteristic can propose an alternate time equal to 2 hours plus the time experienced to accomplish the exponential charging current portion of the battery charge profile following the service test (SR 3.8.4.3).

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within [12] hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within [12] hours (Required Action A.2).

Required Action A.2 requires that the battery float current be verified as less than or equal to [2] amps. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial [12] hour period the battery float current is not less than or equal to [2] amps this indicates there may be additional battery problems and the battery must be declared inoperable.

#### ACTIONS (continued)

Required Action A.3 limits the restoration time for the inoperable battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 day Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

<u>B.1</u>

#### - REVIEWER'S NOTE -

The 2 hour Completion Times of Required Actions B.1 and C.1 are in brackets. Any licensee wishing to request a longer Completion Time will need to demonstrate that the longer Completion Time is appropriate for the plant in accordance with the guidance in Regulatory Guide (RG) 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications."

Condition B represents one division with one [or two] batter[y][ies] inoperable. With one [or two] batter[v][ies] inoperable, the DC bus is being supplied by the OPERABLE battery charger[s]. Any event that results in a loss of the AC bus supporting the battery charger[s] will also result in loss of DC to that division. Recovery of the AC bus, especially if it is due to a loss of offsite power, will be hampered by the fact that many of the components necessary for the recovery (e.g., diesel generator control and field flash, AC load shed and diesel generator output circuit breakers, etc.) likely rely upon the batter[y][ies]. In addition the energization transients of any DC loads that are beyond the capability of the battery charger[s] and normally require the assistance of the batter[y][ies] will not be able to be brought online. The [2] hour limit allows sufficient time to effect restoration of an inoperable battery given that the majority of the conditions that lead to battery inoperability (e.g., loss of battery charger, battery cell voltage less than [2.07] V, etc.) are identified in Specifications 3.8.4, 3.8.5, and 3.8.6 together with additional specific completion times.

## <u>C.1</u>

Condition C represents one division with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for

### ACTIONS (continued)

complete loss of DC power to the affected division. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system division.

If one of the required [Division 1 or 2] DC electrical power subsystems is inoperable for reasons other than Condition A or B (e.g., inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of minimum necessary DC electrical subsystems, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 7) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

## <u>D.1</u>

With the Division 3 DC electrical power subsystem inoperable for reasons other than Condition A or B, the HPCS and 2C Standby Service Water System may be incapable of performing their 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," [and LCO 3.7.1, "Standby Service Water (SSW)] System and [Ultimate Heat Sink (UHS)"]].

## E.1 and E.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).

## SURVEILLANCE REQUIREMENTS

## <u>SR 3.8.4.1</u>

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally 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 recommendations and IEEE-450 (Ref. 8).

## SR 3.8.4.2

This SR verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32 (Ref. 9), the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

This SR provides two options. One option requires that each battery charger be capable of supplying [400] amps at the minimum established float voltage for [8] 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 if sufficient for the charger temperature to have stabilized and to have been maintained for at lease [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 of the status of the plant during which these demands occur). This level of loading may not normally be available following the battery service test and will need to be supplemented with additional loads. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage,

#### SURVEILLANCE REQUIREMENTS (continued)

temperature, an 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 [18 month] intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

## <u>SR 3.8.4.3</u>

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 corresponds to the design duty cycle requirements as specified in Reference 4.

The Surveillance Frequency of [18 months] is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 9) and Regulatory Guide 1.129 (Ref. 10), 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 in lieu of a service test.

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

# SURVEILLANCE REQUIREMENTS (continued)

the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment.

- REFERENCES 1. 10 CFR 50, Appendix A, GDC 17.
  - 2. Regulatory Guide 1.6.
  - 3. IEEE Standard 308, 1978.
  - 4. FSAR, Chapter [8].
  - 5. FSAR, Chapter [6].
  - 6. FSAR, Chapter [15].
  - 7. Regulatory Guide 1.93, December 1974.
  - 8. IEEE Standard 450, 1995.
  - 9. Regulatory Guide 1.32, February 1977.
  - 10. Regulatory Guide 1.129, December 1974.