

AmerGen

An Exelon/British Energy Company

Clinton Power Station

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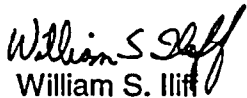
Clinton Power Station, Unit 1
Facility Operating License No. NPF-62
NRC Docket No. 50-461

Subject: Transmittal of Revision 8 to the Clinton Power Station
Technical Specification Bases

In accordance with Clinton Power Station (CPS) Technical Specification 5.5.11, "Technical Specification (TS) Bases Control Program," AmerGen Energy Company, LLC (i.e., AmerGen) is transmitting the revised pages constituting Revision 8 to the CPS TS Bases. The changes associated with this revision were processed in accordance with CPS TS 5.5.11 which became effective with Amendment No. 95 to the CPS Operating License. Compliance with CPS TS 5.5.11 requires updates to the TS Bases to be submitted to the NRC at a frequency consistent with 10CFR50.71(e).

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

Respectfully,



William S. Iliff
Regulatory Assurance Manager
Clinton Power Station

JLP/blf

Attachment – Attachment A: Revision 8 of the CPS Technical Specification Bases

cc: Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Clinton Power Station
Office of Nuclear Facility Safety – Illinois Department of Nuclear Safety

A001

Attachment A
Clinton Power Station, Unit 1
Revision 8 to the CPS Technical Specification Bases

| | | |
|-----------|----------|-----------|
| B 3.2-8 | B 3.6-2 | B 3.6-61 |
| B 3.2-8a | B 3.6-3 | B 3.6-62 |
| B 3.2-8b | B 3.6-4 | B 3.6-64 |
| B 3.3-80 | B 3.6-18 | B 3.6-65 |
| B 3.3-81 | B 3.6-19 | B 3.8-9 |
| B 3.3-82 | B 3.6-20 | B 3.8-10 |
| B 3.3-83 | B 3.6-21 | B 3.8-46 |
| B 3.4-53a | B 3.6-23 | B 3.8-48a |
| B 3.4-61a | B 3.6-24 | |
| B 3.4-61b | B 3.6-53 | |
| B 3.5-25 | B 3.6-54 | |
| B 3.6-1 | B 3.6-55 | |

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.2.2.1

The MCPR is required to be initially calculated within 12 hours after THERMAL POWER is $\geq 21.6\%$ RTP and then every 24 hours thereafter. It is compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation. The 12 hour allowance after THERMAL POWER reaches $\geq 21.6\%$ RTP is acceptable given the large inherent margin to operating limits at low power levels.

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

SR 3.2.2.2

Because the transient analyses may take credit for conservatism in the control rod scram speed performance, it must be demonstrated that the specific scram speed distribution is consistent with that used in the transient analyses. SR 3.2.2.2 determines the actual scram speed distribution and compares it with the assumed distribution.

The MCPR operating limit is then determined based either on the applicable limit associated with scram times of LCO 3.1.4, "Control Rod Scram Times," or the realistic scram times. The scram time dependent MCPR limits are contained in the COLR. This determination must be preformed and any necessary changes must be implemented within 72 hours after each set of control rod scram time tests required by SR 3.1.4.1, SR 3.1.4.2, and SR 3.1.4.4 because the effective scram speed distribution may change during the cycle or after maintenance that could affect scram times. The 72 hour Completion Time is acceptable due to the relatively minor changes in the actual control rod scram speed distribution expected during the fuel cycle.

(continued)

BASES

REFERENCES

1. NUREG-0562, "Fuel Rod Failures As A Consequence of Nucleate Boiling or Dryout," June 1979.
 2. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel, GESTAR-II," (latest approved revision).
 3. USAR, Section 15.0.
 4. USAR, Appendix 15B.
 5. USAR, Appendix 15C.
 6. NEDC-31546-P, "Maximum Extended Operating Domain and Feedwater Heater Out-of-Service Analysis for Clinton Power Station," August 1988.
 7. NEDE-30130-P-A, "Steady State Nuclear Methods," April 1985.
 8. NEDO-24154-A, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," General Electric Company, August 1986.
 9. Calculation IP-0-0002.
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BASES

ACTIONS
(continued)

the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable ATWS-RPT instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable ATWS-RPT instrumentation channel.

A.1

Required Action A.1 is intended to ensure that appropriate actions are taken when a single or multiple, inoperable, untripped channels within the same Function result in the Function not maintaining ATWS-RPT trip capability. A Function is considered to be maintaining ATWS-RPT trip capability when sufficient channels are OPERABLE or in trip such that the ATWS-RPT System will generate a trip signal from the given Function on a valid signal, and both recirculation pumps can be tripped. This requires all four channels of the Function (i.e., both channels in each trip system for the function) to be OPERABLE or in trip, and the four motor breakers (two fast speed and two LFMG) to be OPERABLE or in trip.

The 72 hour Completion Time is sufficient for the operator to take corrective action (e.g., restoration or tripping of channels) and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period and the fact that one Function is still maintaining ATWS-RPT trip capability.

(continued)

BASES

ACTIONS

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within both Functions result in both Functions not maintaining ATWS-RPT trip capability. The description of a Function maintaining ATWS-RPT trip capability is discussed in the Bases for Required Action A.1, above.

The 1 hour Completion Time is sufficient for the operator to take corrective action and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period.

C.1 and C.2

With any Required Action and associated Completion Time not met, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours (Required Action C.2). Alternately, the associated recirculation pump may be removed from service since this performs the intended Function of the instrumentation (Required Action C.1). The allowed Completion Time of 6 hours is reasonable, based on operating experience, both to reach MODE 2 from full power conditions and to remove a recirculation pump from service in an orderly manner and without challenging plant systems.

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BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.3.4.2.1

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

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

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

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.4.2.2

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

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

SR 3.3.4.2.3

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in SR 3.3.4.2.4. If the trip setting is discovered to be less conservative than the setting accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

SR 3.3.4.2.4

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

The Frequency is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

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BASES (continued)

BACKGROUND
(continued)

10 CFR 50, Appendix G (Ref. 1), requires the establishment of P/T limits for material fracture toughness requirements of the RCPB materials. Reference 1 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 2).

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 3) and 10 CFR 50, Appendix H (Ref. 4). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Reference 5.

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.11.8 and SR 3.4.11.9 (continued)

With regard to temperature difference values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Refs. 16, 17).

REFERENCES

1. 10 CFR 50, Appendix G.
2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
3. ASTM E 185-82, "Standard Practice for Conducting Surveillance Tests For Light-Water Cooled Nuclear Power Reactor Vessels."
4. 10 CFR 50, Appendix H.
5. Regulatory Guide 1.99, Revision 2, May 1988.
6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.
7. NEDO-21778-A, "Transient Pressure Rises Affecting Fracture Toughness Requirements for BWRs," December 1978.
8. USAR, Section 15.4.4.
9. USAR, Section 5.3.
10. Deleted
11. Calculation IP-0-0036.
12. Calculation IP-0-0037.
13. Calculation IP-0-0038.
14. Calculation IP-0-0039.

(continued)

BASES

REFERENCES
(continued)

15. Calculation IP-0-0040.
 16. Calculation IP-0-0041.
 17. Calculation IP-0-0042.
 18. GE-NE-B13-02084-00-01, Rev. 0, "Pressure-Temperature Curves for AmerGen, Clinton Power Station Using the K_{Ic} Methodology," August 2000.
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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.5.3.3 and SR 3.5.3.4

The RCIC pump flow rates ensure that the system can maintain reactor coolant inventory during pressurized conditions with the RPV isolated. The flow tests for the RCIC System are performed at two different pressure ranges such that system capability to provide rated flow is tested both at the higher and lower operating ranges of the system. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the RCIC System diverts steam flow. Since the required reactor steam pressure must be available to perform SR 3.5.3.3 and SR 3.5.3.4, sufficient time is allowed after adequate pressure and flow are achieved to perform these SRs. Reactor startup is allowed prior to performing the low pressure Surveillance because the reactor pressure is low and the time to satisfactorily perform the Surveillance is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure test has been satisfactorily completed and there is no indication or reason to believe that RCIC is inoperable. Therefore, these SRs are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test.

A 92 day Frequency for SR 3.5.3.3 is consistent with the Inservice Testing Program requirements. The 18 month Frequency for SR 3.5.3.4 is based on the need to perform this Surveillance under the conditions that apply just prior to or during startup from a plant outage. Operating experience has shown that these components usually pass the SR 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.

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

With regard to the measured reactor pressure and flow rate values obtained pursuant to SR 3.5.3.3, as read from plant instrumentation assumed in Reference 5, are considered to be nominal values and therefore do not require compensation for instrument indication uncertainties.

With regard to the measured reactor pressure and flow rate values obtained pursuant to SR 3.5.3.4, the values as read from plant indication instrumentation are not considered to be nominal values with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Ref. 5).

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Primary Containment

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a Design Basis Accident (DBA) and to confine the postulated release of radioactive material to within limits. The primary containment consists of a steel lined, reinforced concrete vessel, which surrounds the Reactor Primary System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment. Additionally, this structure provides shielding from the fission products that may be present in the primary containment atmosphere following accident conditions.

The isolation devices for the penetrations in the primary containment boundary are a part of the primary containment leak tight barrier. To maintain this leak tight barrier:

- a. All penetrations required to be closed during accident conditions are either:
 1. capable of being closed by an OPERABLE automatic containment isolation system, or
 2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";
- b. Primary containment air locks are OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Locks";
- c. All equipment hatches are closed;
- d. The suppression pool is OPERABLE, except as provided in LCO 3.6.2.2, "Suppression Pool Water Level";
- e. The leakage control system associated with the main steam lines is OPERABLE, except as provided in LCO 3.6.1.8, "Main Steam Isolation Valve (MSIV) Leakage Control System (LCS)"; and

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BASES

BACKGROUND
(continued)

- f. The primary containment leakage rates are within the limits of this LCO.

This Specification ensures that the performance of the primary containment, in the event of a DBA, meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J, Option B (Ref. 3), as modified by approved exemptions.

APPLICABLE
SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

The maximum allowable leakage rate for the primary containment (L_a) is 0.65% by weight of the containment and drywell air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 9.0 psig (Ref. 4).

Primary containment satisfies Criterion 3 of the NRC Policy Statement.

LCO

Primary containment OPERABILITY is maintained by limiting leakage to $\leq 1.0 L_a$, except prior to the first startup after performing a required Primary Containment Leakage Rate Testing Program leakage test. At this time, applicable leakage limits must be met. Compliance with this LCO will

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BASES

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| LCO (continued) | ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis. Individual leakage rates specified for the primary containment air locks are addressed in LCO 3.6.1.2. |
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| | |
|---------------|---|
| APPLICABILITY | In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In other operational conditions, events which could cause a release of radioactive material to primary containment are mitigated by secondary 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, primary containment is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment. |
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| ACTIONS | A Note has been provided to indicate that when the Inclined Fuel Transfer System (IFTS) blind flange is unbolted for removal or reinstallation, entry into the associated Conditions and Required Actions may be delayed for up to 12 hours per operating cycle. This Note applies to the IFTS penetration and not to any other Primary Containment penetration. During removal and reinstallation of the blind flange, a temporary condition will exist where the bolting will be loosened, hydraulic jacks will spread the flange faces, and normally about one half of the bolts will be removed while the blind is rotated. This configuration is expected to exist for no more than a cumulative of 12 hours during MODES 1, 2, and 3. Upon expiration of the 12-hour allowance for this maintenance activity, if the IFTS blind flange has not yet been re-bolted, the applicable Condition must be entered and the required Actions taken. With the bolts removed, the seismic restraint for the IFTS penetration is potentially challenged. The risk is to the bellows assembly, as exact displacements are not quantified. Failure of the ASME Class 2 bellows could result in a potential bypass of containment. Therefore, the total number of hours that the blind flange is unbolted per operating cycle shall be tracked to ensure that the 12-hour limitation is maintained. The cumulative 12-hour duration conservatively limits the seismic risk associated with the unbolted IFTS flange, yet provides adequate time to complete flange rotation. |
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A.1

In the event that primary containment is inoperable, primary containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of

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BASES

ACTIONS

A.1 (continued)

time to correct the problem that is commensurate with the importance of maintaining primary containment OPERABILITY during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring primary containment OPERABILITY) occurring during periods where primary containment is inoperable is minimal.

B.1 and B.2

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

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. Failure to meet air lock leakage testing (SR 3.6.1.2.1), secondary containment bypass leakage (SR 3.6.1.3.8), resilient seal primary containment purge valve leakage testing (SR 3.6.1.3.5), main steam isolation valve leakage (SR 3.6.1.3.9), or hydrostatically tested valve leakage (SR 3.6.1.3.10) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of the Primary Containment Leakage Rate Testing Program. As left leakage prior to the first startup after performing a required leakage test is required to be $\leq 0.6 L_a$ for combined Type B and C leakage, and $\leq 0.75 L_a$ for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of $\leq 1.0 L_a$. At $\leq 1.0 L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

This Surveillance is modified by a Note that requires the leakage rate results of SR 3.6.1.1.2 for the Primary Containment Hydrogen Recombiner System (each loop) to be included in determining compliance with required limits. This can be accomplished either by having the loops in service during the ILRT, or if the loop is not in service during the ILRT, by separately measuring the leakage and including it in the measured ILRT results.

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BASES

ACTIONS
(continued)

The ACTIONS are modified by Notes 3 and 4. These Notes ensure appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable PCIV (e.g., an Emergency Core Cooling System subsystem is inoperable due to a failed open test return valve, or when the primary containment leakage limits are exceeded). Pursuant to LCO 3.0.6, these ACTIONS are not required even when the associated LCO is not met. Therefore, Notes 3 and 4 are added to require the proper actions to be taken.

A fifth note has been added to allow removal of the Inclined Fuel Transfer System (IFTS) blind flange when primary containment operability is required. This provides the option of operating the IFTS for testing, maintenance, or movement of new (non-irradiated) fuel to the upper containment pool when primary containment operability is required. Requiring the fuel building fuel transfer pool water to be \geq el. 753 ft. ensures a sufficient depth of water over the highest point on the transfer tube outlet valve in the fuel building fuel transfer pool to prevent direct communication between the containment building atmosphere and the fuel building atmosphere via the inclined fuel transfer tube. Because excessive leakage of water from the upper containment pool through the open IFTS penetration would result in the inability to provide the required volume of water to the suppression pool in an upper pool dump, an administrative control was required to ensure the upper pool volume meets the design requirements. In addition to the dedicated individual stationed at the IFTS controls, the required administrative controls involved the installation of the Steam Dryer Pool to Reactor Cavity Pool gate with the seal inflated and a backup air supply provided. Since the IFTS transfer tube drain line does not have the same water level as the transfer tube, and the motor-operated drain valve remains open when the carriage is in the lower pool, administrative controls are required to ensure the drain line flow path is quickly isolated in the event of a LOCA. In this instance, administrative controls of the IFTS transfer tube drain line isolation valve(s) include stationing a dedicated individual, who is in continuous communication with the control room, at the IFTS control panel in the fuel building. This individual will initiate closure of the IFTS transfer tube drain line motor-operated isolation valve (1F42-F003) and the IFTS transfer tube drain line manual isolation valve (1F42-F301) if a need for primary containment isolation is indicated. The pressure integrity of the IFTS transfer tube, the seal created by water depth of the fuel building transfer pool, and the administrative control of the drain line flow path create an acceptable barrier to prevent the post-accident containment building atmosphere from leaking into the fuel building.

The total time per operating cycle that the blind flange may be open in Modes 1, 2, and 3 without affecting plant risk levels is 40 days.

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BASES

ACTIONS

A.1 and A.2

With one or more penetration flow paths with one PCIV inoperable except for inoperability due to leakage not within a limit specified in an SR to this LCO, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest one available to the primary containment. The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines and 12 hours for instrument line excess flow check valves (EFCVs)). The specified time period of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown. For EFCVs, a 12 hour Completion Time is allowed. The Completion Time of 12 hours for EFCVs allows a period of time to restore the EFCVs to OPERABLE status given the fact that these valves are associated with instrument lines which are of small diameter and thus represent less significant leakage paths.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be isolated should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside primary containment, drywell, and steam tunnel and capable of being mispositioned are in the correct position. The Completion Time for this verification of "once per 31 days for isolation devices outside primary containment; drywell, and steam tunnel," is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For devices inside primary containment, drywell, or steam tunnel, the specified time period of "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 the existence of other administrative controls ensuring that device misalignment is an unlikely

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

possibility.

Required Action A.2 is modified by a Note that applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment; once they have been verified to be in the proper position, is low.

B.1

With one or more penetration flow paths with two PCIVs inoperable, except due to leakage not within limits, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

C.1

With the secondary containment bypass leakage rate, hydrostatic leakage rate, or MSIV leakage rate not within limit, the assumptions of the safety analysis may not be met. Therefore, the leakage must be restored to within limit within 4 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated, the leakage rate for the isolation penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The 4 hour Completion Time is reasonable considering the time required to restore the leakage by isolating the penetration and the relative importance to the overall containment function.

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

In the event one or more primary containment purge valves are not within the purge valve leakage limits, purge valve leakage must be restored to within limits or the affected penetration must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, closed manual valve, and blind

(continued)

BASES

ACTIONS

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

flange. If a purge valve with resilient seals is utilized to satisfy Required Action D.1, it must have been demonstrated to meet the leakage requirements of SR 3.6.1.3.5. The specified Completion Time is reasonable, considering that one primary containment purge valve remains closed (refer to the requirements of SR 3.6.1.3.1; if this requirement is not met, entry into Condition A and B, as appropriate, would also be required), so that a gross breach of primary containment does not exist.

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

For a primary containment purge valve with a resilient seal that is isolated in accordance with Required Action D.1, SR 3.6.1.3.5 must be performed at least once every 92 days. This provides assurance that degradation of the resilient seal is detected and confirms that the leakage rate of the primary containment purge valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.1.3.5 is as required by the Primary Containment Leakage Rate Testing Program. Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown acceptable based on operating experience.

E.1 and E.2

If any Required Action and associated Completion Time cannot be met 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

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.2 (continued)

these devices, once they have been verified to be in the proper position, is low. A second Note is included to clarify that PCIVs open under administrative controls are not required to meet the SR during the time the PCIVs are open.

SR 3.6.1.3.3

This SR verifies that each primary containment manual isolation valve and blind flange located inside primary containment, drywell, or steam tunnel, and required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. For devices inside primary containment, drywell, and steam tunnel, the Frequency of "prior to entering MODE 2 or 3 from MODE 4, if not performed within the previous 92 days", is appropriate since these devices are operated under administrative controls and the probability of their misalignment is low.

Two Notes are added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since access to these areas is typically restricted during MODES 1, 2, and 3. Therefore, the probability of misalignment of these devices, once they have been verified to be in their proper position, is low. A second Note is included to clarify that PCIVs that are open under administrative controls are not required to meet the SR during the time that the PCIVs are open.

(continued)

BASES

|
SURVEILLANCE
REQUIREMENTS

SR 3.6.1.3.4

Verifying the isolation time of each power operated and each automatic PCIV is within limits is required to demonstrate OPERABILITY. MSIVs may be excluded from this SR since MSIV full closure isolation time is demonstrated by SR 3.6.1.3.6. The isolation time test ensures that the valve will isolate

(continued)

B 3.6 CONTAINMENT SYSTEMS

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 146,400 ft³ at the low water level limit of 18 ft 11 inches and 150,230 ft³ at the high water level limit of 19 ft 5 inches. in MODES 1, 2, and 3. (These volume values do not explicitly exclude a volume of approximately 500 ft³ rendered unavailable due to the additional displacement of suppression pool water caused by the ECCS/RCIC suction strainers that were introduced by plant modification M-083. Analysis has shown that this volume impact is negligible.) In MODE 3, with reactor pressure less than 235 psig and the upper containment pool level less than the limit, the lower and upper limits are 19 ft 9 inches and 20 ft 1 inches. The lower limit is controlled by Technical Specification 3.6.2.4 when the upper containment pool is drained.

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

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

within the limits specified so that the safety analysis of Reference 1 remains valid.

Suppression pool water level satisfies Criteria 2 and 3 of the NRC Policy Statement.

LCO

A limit that suppression pool water level be ≥ 18 ft 11 inches and ≤ 19 ft 5 inches (or ≥ 18 feet 11 inches and ≤ 20 ft 1 inches in MODE 3 with reactor pressure less than 235 psig) 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. Requirements for suppression pool level in MODE 4 or 5 are 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 horizontal vents are covered, RCIC turbine exhaust is 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 and due to OPERABLE containment sprays. 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.

(continued)

BASES

ACTIONS
(continued)

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 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 3.6.2.2.1

Verification of the suppression pool water level is to ensure that the 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.

With regard to the suppression pool water minimum level values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures. The suppression pool maximum water level values are considered to be nominal values and do not require compensation for instrument uncertainties (Ref. 2).

REFERENCES

1. USAR, Section 6.2.
 2. Calculation IP-0-0049.
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BASES

BACKGROUND
(continued)

- d. Allowances for primary containment spray holdup on equipment and structural surfaces.

The SPMU System consists of two redundant subsystems, each capable of dumping the makeup volume from the upper containment pool to the suppression pool by gravity flow. Each dump line includes two normally closed valves in series. The upper pool is dumped automatically on a suppression pool water level-Low Low signal (with a LOCA signal permissive) or on the basis of a timer following a LOCA signal alone to ensure that the makeup volume is available as part of the long term energy sink for small breaks that might not cause dump on a suppression pool water level-Low Low signal. A 30 minute timer was chosen, since the initial suppression pool mass is adequate for any sequence of vessel blowdown energy and decay heat up to at least 30 minutes.

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

Analyses used to predict suppression pool temperature following large and small break LOCAs, which are the applicable DBAs for the SPMU System, are contained in References 1 and 2. During these events, the SPMU System is relied upon to dump upper containment pool water to maintain drywell horizontal vent coverage and an adequate suppression pool heat sink volume to ensure that the primary containment internal pressure and temperature stay within design limits. The analysis assumes an SPMU System dump volume of 14,652 ft³ at a temperature of 120°F. Reference 6 contains an analysis for LOCAs in MODE 3 with reactor pressure less than 235 psig.

The SPMU System satisfies Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

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. 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 containment pool water temperature is $\leq 120^{\circ}\text{F}$, the water level is $\geq \text{el. } 827 \text{ ft } 1 \text{ inch}$, $\geq \text{el. } 825 \text{ ft } 10 \text{ inches}$ with the reactor cavity to steam dryer storage pool gate open, or $\geq \text{el. } 825 \text{ ft } 6 \text{ inches}$ with both the reactor cavity to steam dryer storage pool gate and the steam dryer storage pool to the inclined fuel transfer pool gate open, the piping is intact, and the system valves are OPERABLE. Two alternatives to the above SPMU operability requirements exist when the plant is in MODE 3 with reactor pressure level less than 235 psig. In this condition, the combined upper containment pool and suppression pool water volumes may be used. The reactor cavity pool portion of the upper containment pool water level must be greater than el. 824 ft 7 inches, or the suppression pool water level needs to be greater than 19 ft 9 inches, to assure that there is sufficient water between the two sources. The level limits in MODE 3 account for all gate positions. The above temperature and water level conditions correspond to an SPMU System available dump volume of $\geq 14,652 \text{ ft}^3$, except for the alternative SPMU operability requirements in MODE 3, which assumes the available upper pool dump volume is $\geq 3694 \text{ ft}^3$.

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

A.1

When the combined upper containment pool and suppression pool water levels are less than required, 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 horizontal vents. Loss of water volume has a relatively large impact on heat sink capability. Therefore, the combined upper containment pool and suppression pool water levels 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.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.4.1 (continued)

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.

A fourth and fifth method (Items d. and e.) may be used to determine that there is sufficient water level combined between the upper containment pool and suppression pool when reactor pressure is less than 235 psig in MODE 3. The water level of the reactor cavity pool portion of the upper containment pool must be greater than el. 824 ft 7 inches, or the suppression pool water level must be greater than 19 ft 9 inches to satisfy this requirement.

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

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.

With regard to the water level values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Ref. 5).

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 potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.2.4.3 (continued)

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.

SR 3.6.2.4.4

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. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.4.7 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.

This SR is modified by a Note that excludes make up to the suppression pool. Since all active components are testable, makeup to the suppression pool is not required.

REFERENCES

1. USAR, Section 6.2.
 2. USAR, Chapter 15.
 3. USAR, Section 6.2.7.
 4. Calculation IP-0-0074.
 5. Calculation IP-0-0075.
 6. Calculation IP-M-0662.
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BASES

ACTIONS
(continued)

B.4

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. Although Condition B applies to a single inoperable DG, several Completion Times are specified for this Condition.

The first Completion Time applies to an inoperable Division 3 DG. The 72-hour 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 during this period. This Completion Time begins only "upon discovery of an inoperable Division 3 DG" and, as such, provides an exception to the normal "time zero" for beginning the allowed outage time "clock" (i.e., for beginning the clock for an inoperable Division 3 DG when Condition B may have already been entered for another equipment inoperability and is still in effect).

The second Completion Time (14 days) applies to an inoperable Division 1 or 2 DG and is a risk-informed allowed out-of-service time (AOT) based on a plant-specific risk analysis performed to establish this AOT for the Division 1 and 2 DGs.

The evaluation that supports this Completion Time considered both planned and unplanned DG outage time. Based on this evaluation, it is intended that use of the full, 14-day completion time would be limited to once per DG per cycle (18 months) to perform a planned DG overhaul.

To mitigate increased risk during the period beyond 72 hours and up to 14 days, the following actions must be completed prior to exceeding 72 hours:

- Verification that the RAT and ERAT are operable.
- Verification of the correct breakers alignment and indicated power availability for each offsite circuit.
- The DG extended Completion Time will not be entered for scheduled maintenance purposes if severe weather conditions are expected.
- Additional elective equipment maintenance or testing that requires the equipment to be removed from service will be evaluated and activities that yield unacceptable results will be avoided.
- The condition of the offsite power supply and switchyard, including transmission lines and ring bus breakers, will be evaluated.
- No elective maintenance will be scheduled within the switchyard that would challenge the RAT connection or offsite power availability.

(continued)

BASES

ACTIONS

B.4 (continued)

- Operating crews will be briefed on the DG work plan with consideration given to actions that would be required in the event of a loss of offsite power or station blackout.

The third 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 17 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 20 days) allowed prior to complete restoration of the LCO. The 17-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 Completion Times means that the three Completion Times apply simultaneously, and the most 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 rationale for the 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 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.

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.8.3.3 (continued)

tests listed in the Diesel Fuel Oil Testing Program of Specification 5.5.9 are as follows:

- a. Sample the new fuel oil in accordance with ASTM D4057-95 (Ref. 6);
- b. Verify in accordance with the tests specified in ASTM D1298-99 (Ref. 6) that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.87 (or an API gravity at 60°F of $\geq 30^\circ$ and $\leq 40^\circ$), and in accordance with the tests specified in ASTM D975-98b (Ref. 6) that the sample has a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes; and
- c. Verify that the new fuel oil has clear and bright appearance with proper color when tested in accordance with ASTM D4176-93 (Ref. 6), or a water and sediment content ≤ 0.05 v/o when tested in accordance with ASTM-D975-98b.

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.

Following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-98b (Ref. 6) are met for new fuel oil when tested in accordance with ASTM D975-98b (Ref. 6). These additional analyses are required by Specification 5.5.9, Diesel Fuel Oil Testing Program, to be performed within 31 days following sampling and addition. This 31 days is intended to assure: 1) that the sample taken is not more than 31 days old at the time of adding the fuel oil to the storage tank, and 2) that the results of a new fuel oil sample (sample obtained prior to addition but not more than 31 days prior to) are obtained within 31 days after addition. 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.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.8.3.6

Draining of the fuel oil stored in the supply tanks, removal of accumulated sediment, and tank cleaning are required at 10 year intervals by Regulatory Guide 1.137 (Ref. 2), paragraph 2.f. This SR is typically performed in conjunction with the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 7), examinations of the tanks. To preclude the introduction of surfactants in the fuel oil system, the cleaning should be accomplished using sodium hypochlorite solutions, or their equivalent, rather than soap or detergents. This SR is for preventive maintenance. The presence of sediment does not necessarily represent a failure of this SR provided that accumulated sediment is removed during performance of the Surveillance.

REFERENCES

1. USAR, Section 9.5.4.
2. Regulatory Guide 1.137.
3. ANSI N195, Appendix B, 1976.
4. USAR, Chapter 6.
5. USAR, Chapter 15.
6. ASTM Standards: D4057-95; D1298-99; D975-98b; D4176-93; D2276-88.
7. ASME, Boiler and Pressure Vessel Code, Section XI.
8. Calculation IP-0-0120.
9. Calculation IP-0-0121.
10. Calculation IP-0-0122.
11. Calculation IP-C-0111.