Florida Power
CORPORATION
Crystal River Unit 3
Docket No. 50-302
Operating License No. DPR-72

April 27, 2000
3F0400-07

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

Subject: Technical Specifications Bases Control Program

Dear Sir:

Florida Power Corporation (FPC) hereby submits the changes that were made to the Crystal River Unit 3 (CR-3) Improved Technical Specifications (ITS) Bases as required by ITS 5.6.2.17. The attachments provide revisions to the CR-3 ITS Bases that will update NRC copies of the ITS. Each change was reviewed by the Plant Review Committee. Copies are maintained as CR-3 quality records and are available for review.

Attachment A provides the instructions for updating the CR-3 ITS. Attachment B provides the ITS and Bases List of Effective Pages. Attachment C provides the replacement pages for the CR-3 ITS Bases.

If you have any questions regarding this submittal, please contact Mr. Sid Powell, Manager, Nuclear Licensing at (352) 563-4883.

Sincerely,

SLBernhoft

S. L. Bernhoft
Director, Nuclear Regulatory Affairs

SLB/ff

Attachments

xc: NRR Project Manager (w/o Attachment C)
Regional Administrator, Region II (w/o Attachment C)
Senior Resident Inspector (w/o Attachment C)

A001

FLORIDA POWER CORPORATION

CRYSTAL RIVER UNIT 3

DOCKET NUMBER 50-302/LICENSE NUMBER DPR-72

ATTACHMENT A

INSTRUCTIONS FOR UPDATING THE CRYSTAL RIVER UNIT 3 IMPROVED TECHNICAL SPECIFICATIONS (ITS) AND BASES

INSTRUCTIONS FOR UPDATING
THE CRYSTAL RIVER UNIT 3
IMPROVED TECHNICAL SPECIFICATIONS

4/27/00

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THE CRYSTAL RIVER UNIT 3
IMPROVED TECHNICAL SPECIFICATIONS

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THE CRYSTAL RIVER UNIT 3
IMPROVED TECHNICAL SPECIFICATIONS

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THE CRYSTAL RIVER UNIT 3
IMPROVED TECHNICAL SPECIFICATIONS

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FLORIDA POWER CORPORATION

CRYSTAL RIVER UNIT 3

DOCKET NUMBER 50-302/LICENSE NUMBER DPR-72

ATTACHMENT B

ITS AND BASES LIST OF EFFECTIVE PAGES

IMPROVED TECHNICAL SPECIFICATION BASES

List of Effective Pages
(Through Amendment 191 and ITS Bases Revision 25)

Amendment Nos. 159, 164, 166, 171, 173, 181, 189 and 190 amended the CR-3 Operating License, only, and did not effect changes to the ITS LCOs or Bases.

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IMPROVED TECHNICAL SPECIFICATION BASES

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FLORIDA POWER CORPORATION

CRYSTAL RIVER UNIT 3

DOCKET NUMBER 50-302/LICENSE NUMBER DPR-72

ATTACHMENT C

REPLACEMENT ITS BASES PAGES

BASES (continued)

APPLICABILITY (continued)

In MODES 3, 4, 5, and 6, Applicability is not required, since the reactor is not generating significant THERMAL POWER.

SAFETY LIMIT VIOLATIONS

The following SL violation responses are applicable to the reactor core SLs.

2.2.1

If SL 2.1.1.1, SL 2.1.1.2, or SL 2.1.1.3 is violated, the requirement to go to MODE 3 places the plant in a MODE in which these SLs can not be violated.

The allowed Completion Time of 1 hour recognizes the importance of placing the plant in a MODE of operation where these SLs are not applicable and reduces the probability of fuel damage.

2.2.4

If SL 2.1.1.1, SL 2.1.1.2, or SL 2.1.1.3 is violated, the NRC Operations Center must be notified within 1 hour, in accordance with 10 CFR 50.72 (Ref. 3).

The 10 CFR 50.72 part against which a Safety Limit violation would be reported is the declaration of any of the Emergency Classes specified in the Emergency Plan (10 CFR 50.72(a)(1)(i)).

2.2.5

If SL 2.1.1.1, SL 2.1.1.2, or SL 2.1.1.3 is violated, the appropriate Nuclear Operations senior management and the Nuclear General Review Committee (NGRC) shall be notified within 24 hours. This 24 hour period provides time for the plant operators and staff to take the appropriate immediate action and assess the condition of the plant before reporting to senior management.

(continued)

BASES

SAFETY LIMIT VIOLATIONS (continued)

2.2.6

If SL 2.1.1.1, SL 2.1.1.2, or SL 2.1.1.3 is violated, a Licensee Event Report shall be prepared and submitted within 30 days to the NRC in accordance with 10 CFR 50.73 (Ref. 4). A copy of the report shall also be provided to the NGRC, the Director, Nuclear Plant Operations, and the Chief Nuclear Officer.

The 10 CFR 50.73 part against which a Safety Limit violation would be reported is: 1) completion of a plant shutdown required by Technical Specifications, (10 CFR 50.73(a)(2)(i)(A)), 2) an event which resulted in an unanalyzed condition that significantly compromised plant safety, (10 CFR 50.73(a)(2)(ii)(A)), 3) any condition outside the design basis for the plant (10 CFR 50.73(a)(2)(ii)(B)), and 4) an event which resulted in an RPS actuation (10 CFR 50.73(a)(2)(iv)).

2.2.7

If SL 2.1.1.1, SL 2.1.1.2, or SL 2.1.1.3 is violated, operation of the plant shall not be resumed until authorized by the NRC. This requirement ensures the NRC that all necessary reviews, analyses, and actions are completed before the plant enters the applicable MODES for these SLs (MODES 1 and 2).

REFERENCES

1. FSAR, Section 1.4.

2. FSAR, Table 7-2.

3. 10 CFR 50.72.

4. 10 CFR 50.73.

5. 10 CFR 50.36.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

during secondary system chemistry control and steam generator cleaning, the initial SDM in the core must be adjusted. The basis for the SDM shutdown requirement when high steam generator levels exist is the heat removal potential in the secondary system fluid and the negative reactivity added via MTC. At any given initial primary system temperature and its associated secondary system pressure, the secondary system liquid levels can be equated to a final primary system temperature assuming the entire mass is boiled. The resulting RCS temperature determines the required SDM.

SDM satisfies Criterion 2 of the NRC Policy Statement.

LCO

SDM requirements assume the highest worth rod is stuck in the fully withdrawn position to account for a postulated untrippable rod prior to reactor shutdown.

A figure in the COLR, or boration of the RCS to SDM requirements for 73°F is used to define the SDM when high steam generator levels exist during secondary system chemistry control and steam generator cleaning in MODES 3, 4, and 5. This represents a series of initial conditions that ensure the core will remain subcritical following an MSLB accident initiated from those conditions. Boration of the RCS to 1% Δ k/k SDM for 73°F is required by plant cooldown procedure prior to bypass of EFIC actuation on low steam generator pressure.

APPLICABILITY

In MODES 3, 4, and 5, the SDM requirements ensure sufficient negative reactivity to meet the assumptions of the safety analysis discussed above. In MODES 1 and 2, SDM is ensured by complying with LCO 3.1.5 and LCO 3.2.1. In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, "Boron Concentration."

ACTIONS

A.1

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. It is assumed that boration to restore SDM will be continued until the SDM requirements are met. If the SDM is less than the limit

(continued)

BASES

ACTIONS

A.1 (continued)

for the steam generator level and RCS temperature specified in the COLR or 1% Δ k/k, RCS boration must be continued until the applicable limit is met.

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a highly concentrated solution, such as that normally found in the boric acid storage tank or the borated water storage tank. The operator should borate with the best source available given the existing plant conditions.

In determining the boration flow rate, the time in core life must be considered. For instance, the most difficult time in core life to increase the RCS boron concentration is at the beginning of cycle, when the boron concentration may approach or exceed 2000 ppm. For example, pumping a boric acid solution with 11,600 ppm boron at 10 gpm will result in the addition of 1% Δ k/k negative reactivity in approximately 120 minutes at typical BOC conditions. Slightly shorter times can be achieved when the same negative reactivity addition is made later in the fuel cycle when the initial RCS boron concentration is lower. Other flowrates and boric acid supply concentrations can be used to provide equivalent results.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

The SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. RCS boron concentration;

b. Regulating rod position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration; and

f. Samarium concentration.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.3.2

The requirement for measurement, within 7 effective full power days (EFPD) after reaching a RTP equilibrium boron concentration equivalent to 300 ppm, satisfies the confirmatory check on the most negative (least positive) MTC value. The measurement is performed at any THERMAL POWER equivalent to an RCS boron concentration of 300 ppm (for steady state operation at RTP with all CONTROL RODS (Control Rod Groups 1-7) fully withdrawn, and correction for B-10 depletion) so that the projected EOC MTC may be evaluated before the reactor actually reaches the EOC condition. MTC values are extrapolated from the measurement burnup to the EOC EFPD and compensated to permit direct comparison to the specified MTC limits.

The SR is modified by two Notes. Note 1 indicates performance of SR 3.1.3.2 is not required prior to entering MODE 1 or 2. Since the reactor must be critical in order to obtain meaningful data from the Surveillance, entry into MODE 1 prior to performing the Surveillance is necessary and allowed.

Note 2 indicates that SR 3.1.3.2 may be repeated if MTC is projected to exceed the lower limit prior to the end of the operating cycle. This subsequent performance must occur prior to exceeding the minimum allowable boron concentration at which MTC is projected to exceed the lower limit. The minimum allowable boron concentration is obtained from the EOC MTC versus boron concentration slope with appropriate conservatisms. Thus, the extrapolated EOC MTC may be much more conservative than the actual measured value. In any case, shutdown must occur upon exceeding the lower MTC limit (be it projected or measured).

REFERENCES

1. 10 CFR 50, Appendix A, GDC 11.

2. FSAR, Chapter 14.

3. FSAR, Section 14.1.2.2.

4. FSAR, Section 14.2.2.4.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Fuel cladding damage does not occur when the core is operated outside the conditions of these LCOs during normal operation. However, fuel cladding damage could result if an accident occurs with the simultaneous violation of one or more of the LCOs limiting the regulating rod position, the APSR position, the AXIAL POWER IMBALANCE, and the QPT. This potential for fuel cladding damage exists because changes in the power distribution can cause increased power peaking and correspondingly increased local linear heat rates (LHRs).

The SDM requirement is met by limiting the regulating and safety rod insertion limits such that sufficient inserted reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin that assumes that the maximum worth rod remains fully withdrawn upon trip (Ref. 4). Operation at the SDM based regulating rod insertion limit may also indicate that the maximum ejected rod worth could be equal to the limiting value.

Operation at the regulating rod insertion limits may cause the local core power to approach the maximum allowed linear heat generation rate or peaking factor with the maximum allowed QPT and maximum allowable AXIAL POWER IMBALANCE present.

The regulating rod and safety rod insertion limits ensure that the safety analysis assumptions for ejected rod worth, SDM, and power distribution peaking factors remain valid (Refs. 3, 5, and 6).

The regulating rod insertion limits LCO satisfies Criterion 2 of the NRC Policy Statement.

LCO

The limits on CONTROL ROD sequence, including group overlap, and insertion positions as defined in the COLR, must be maintained because they ensure that the resulting power distribution is within the range of analyzed power distributions and that the SDM and ejected rod worth are maintained.

(continued)

BASES

LCO (continued)

Measurement system-independent limits for regulating rod insertion are provided in the COLR. Measurement system-dependent maximum allowable setpoints are derived by an adjustment of the measurement system-independent limits to allow for THERMAL POWER level uncertainty and rod position errors.

Actual alarm setpoints are more restrictive than the maximum allowable setpoint values to provide additional conservatism between the actual alarm setpoint and the measurement system independent limit.

APPLICABILITY

The regulating rod sequence, overlap, and physical insertion limits shall be maintained with the reactor in MODES 1 and 2. These limits maintain the validity of the assumed power distribution, ejected rod worth, SDM, and reactivity rate insertion assumptions used in the safety analyses. Applicability in MODES 3, 4, and 5 is not required, because neither the power distribution nor ejected rod worth assumptions are exceeded in these MODES. SDM in MODES 3, 4, and 5 is governed by LCO 3.1.1, "SHUTDOWN MARGIN (SDM)."

LCO 3.2.1 has been modified by a Note that suspends the LCO requirement during the performance of SR 3.1.4.2, which verifies the freedom of the rods to move. Dependent on the rod group, this SR results in violation of the LCO limit on sequence and insertion. This is considered acceptable since temporary insertion and withdrawal, in accordance with SR 3.1.4.2, will not impact the core power distribution or shutdown capability significantly.

In MODES 1 and 2, it may be necessary to suspend the Regulating Rod Insertion Limits (for the restricted operation region only) during PHYSICS TESTS per LCO 3.1.8, "PHYSICS TESTS Exceptions - Mode 1" and LCO 3.1.9, "PHYSICS TEST Exceptions - Mode 2." Suspension of these limits is permissible because the reactor protection criteria are maintained by the remaining LCO(s) governing the three dimensional power distribution and by the Surveillance Requirements of LCO 3.1.8 and LCO 3.1.9.

(continued)

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 AXIAL POWER SHAPING ROD (APSR) Insertion Limits

BASES

BACKGROUND

The insertion limits of the APSRs are initial condition assumptions in all safety analyses that are affected by core power distributions. The applicable criterion for these power distribution design requirements are FSAR Section 1.4, Criterion 6, "Reactor Core Design", (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants" (Ref. 2).

Limits on APSR insertion have been established, and all APSR positions are monitored and controlled during power operation to ensure that the power distribution defined by the design power peaking limits is maintained.

The power density at any point in the core must be limited to maintain specified acceptable fuel design limits, including limits that meet the criteria specified in Reference 2. Together, LCO 3.2.1, "Regulating Rod Insertion Limits," LCO 3.2.2, "AXIAL POWER SHAPING ROD (APSR) Insertion Limits," LCO 3.2.3, "AXIAL POWER IMBALANCE Operating Limits," and LCO 3.2.4, "QUADRANT POWER TILT (QPT)," provide limits on control component operation and on monitored process variables to ensure that the core operates within the $F_Q(Z)$ and $F^N_{\Delta H}$ limits in the COLR. Operation within the $F_Q(Z)$ limits given in the COLR prevents power peaks that exceed the loss of coolant accident (LOCA) limits derived from the analysis of the Emergency Core Cooling Systems (ECCS). Operation within the $F^N_{\Delta H}$ limits given in the COLR prevents departure from nucleate boiling (DNB) during a loss of forced reactor coolant flow accident. The APSRs are not required for reactivity insertion rate on trip or SDM and, therefore, they do not trip upon a reactor trip.

This LCO is required to minimize fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a LOCA, loss of flow accident, ejected rod accident, or other postulated accident requiring termination by a Reactor Protection System trip function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation (Condition I) or anticipated operational occurrences (Condition II). Acceptance criteria for the safety and regulating rod insertion, APSR position, AXIAL POWER IMBALANCE, and QPT LCOs preclude core power distributions that violate the following fuel design criteria:

a. During a large break LOCA, the peak cladding temperature must not exceed 2200°F (Ref. 2);

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a DNB condition (Ref. 4); and

c. During an ejected rod accident, the fuel enthalpy must not exceed 280 cal/gm (Ref. 3).

Fuel cladding damage does not occur when the core is operated outside these LCOs during normal operation. However, fuel cladding damage could result should an accident occur simultaneously with violation of one or more of these LCOs. This potential for fuel cladding damage exists because changes in the power distribution can cause increased power peaking and corresponding increased local linear heat rates.

Operation at the APSR insertion limits may approach the maximum allowable linear heat generation rate or peaking factor with the allowed QPT present.

The APSR insertion limits satisfy Criterion 2 of the NRC Policy Statement.

LCO

The limits on APSR physical insertion as defined in the COLR must be maintained because they serve the function of controlling the power distribution within an acceptable range.

Measurement system-independent limits for APSR insertion are provided in the COLR. Measurement system-dependent maximum allowable setpoints are derived by adjustment of the measurement system-independent limits to allow for THERMAL POWER level uncertainty and rod position errors.

(continued)

BASES

LCO (continued)

Actual alarm setpoints are more restrictive than the maximum allowable setpoint values to allow for additional conservatism between the actual alarm setpoints and the measurement system independent limits.

APPLICABILITY

The APSR physical insertion limits shall be maintained with the reactor in MODES 1 and 2. These limits maintain the power distribution within the range assumed in the accident analyses. In MODE 1, the limits on APSR insertion specified by this LCO maintain the axial fuel burnup design conditions assumed in the reload safety evaluation analysis. In MODE 2, applicability is required because $k_{eff} \geq 0.99$. Applicability in MODES 3, 4, and 5 is not required, because the power distribution assumptions in the accident analyses would not be exceeded in these MODES.

ACTIONS

For steady state power operation, a normal position for APSR insertion is specified in the station operating procedures. The APSRs may be positioned as necessary for transient AXIAL POWER IMBALANCE control until the fuel cycle design requires them to be fully withdrawn. (Not all CR-3 fuel cycles incorporate APSR withdrawal.) If the fuel cycle design incorporates an APSR withdrawal (usually near end of cycle (EOC)), the APSRs may not be maintained in the fully withdrawn position prior to the fuel cycle burnup for the APSR withdrawal. If this occurs, the APSRs must be restored to their normal inserted position. Conversely, after the fuel cycle burnup for the APSR withdrawal occurs, the APSRs may not be reinserted for the remainder of the fuel cycle. These restrictions ensure the axial burnup distribution that accumulates in the fuel will be consistent with the expected (as designed) distribution.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

For verification that the core parameters $F_Q(Z)$ and $F^N_{\Delta H}$ are within their limits, SR 3.2.5.1 is performed using the Incore Detector System to obtain a three dimensional power distribution map. Successful verification that $F_Q(Z)$ and $F^N_{\Delta H}$ are within their limits ensures that operation with the APSRs inserted or withdrawn in violation of the times specified in plant procedures does not violate either the ECCS or DNB criteria. The Completion Time of 2 hours is reasonable to obtain a power distribution map and to verify the power peaking factors. Repeating SR 3.2.5.1 every 2 hours is reasonable to ensure that continued verification of the power peaking factors is obtained as core conditions (primarily the regulating rod insertion and induced xenon redistribution) change.

Since Required Action A.1 only specifies a "perform", a failure of SR 3.2.5.1 acceptance criteria does not result in a Required Action not met (Condition B of this Specification). However, when SR 3.2.5.1 is not met, the Required Actions of LCO 3.2.5 are applicable. The conservative power reductions specified by the Required Actions for LCO 3.2.5 ensure the core continues to operate within an acceptable region for the duration of the Completion Time.

In the event that the APSR position indication system is found to be inoperable, it is overly conservative to assume the APSR insertion limits are not met. Instead, the APSR is considered to be inoperable and the Required Actions of LCO 3.1.6, "APSR Alignment Limits," apply.

Indefinite operation with the APSRs inserted or withdrawn in violation of the times specified in the COLR is not prudent. Even if power peaking monitoring per Required Action A.1 is continued, the abnormal APSR insertion or withdrawal may cause an adverse xenon redistribution, may cause the limits on AXIAL POWER IMBALANCE to be exceeded, or may affect the long term fuel depletion pattern. Therefore, power peaking monitoring is allowed for up to 24 hours. This Completion Time is reasonable based on the low probability of an event occurring simultaneously with the APSR limit out of specification. In addition, it precludes long term

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.5.1 (continued)

for exceeding both the power peaking factors assumed in the accident analyses due to operation with unanalyzed core power distributions and spatial xenon distributions beyond their analyzed ranges.

The measured value of F_Q is increased by 2.0% to account for manufacturing tolerances on the fuel and further increased by 7.5% to account for measurement uncertainty. $F^N_{\Delta H}$ is increased by 5% for measurement uncertainty.

REFERENCES

1. 10 CFR 50.46.

2. BAW-10143P-A, Rev. 1, "BWC Correlation of Critical Heat Flux", April 1985.

BASES

BACKGROUND (continued)

Main Turbine Control Oil Pressure

Main Turbine Control Oil Pressure is an input to the Main Turbine Trip anticipatory reactor trip, Function 9. Each of the four protection channels receives turbine status information from four identical pressure switches monitoring main turbine automatic stop oil pressure. An open indication will be provided to the RPS on a turbine trip. Contact buffers in each protection channel continuously monitor the status of the contact inputs and initiate an RPS trip when a turbine trip is indicated.

Main Feedwater Pump Control Oil Pressure

Main Feedwater Pump Control Oil Pressure is an input to the Loss of Main Feedwater Pumps trip, Function 10. Control oil pressure is measured by four pressure switches on each feedwater pump. One switch on each pump is associated with each protection channel.

RPS Bypasses

The RPS is designed with two types of bypasses: channel bypass and shutdown bypass.

Channel bypass provides a method for placing all Functions in one RPS protection channel in a bypassed condition, and shutdown bypass provides a method of leaving the safety rods withdrawn during cooldown and depressurization of the RCS. Each bypass is discussed in more detail below.

Channel Bypass

A channel bypass provision is provided to allow for maintenance and testing of the RPS. The use of channel bypass keeps the protection channel trip relay energized regardless of the status of the instrumentation channel or the bistable relay contacts. In order to place an RPS channel in channel bypass, two conditions must be met. First, the other three channels must not be in channel bypass. This interlock prevents more than one channel at a time being placed in bypass and is ensured by in-series

(continued)

BASES

BACKGROUND

Channel Bypass (continued)

contacts from the other channels with the channel bypass relay. If any contact is open, the second channel cannot be bypassed. The second condition is the closing of the key switch. When the bypass relay is energized, the bypass contact closes, maintaining the channel trip relay in an energized condition. All RPS trip logics are reduced to a two-out-of-three logic in channel bypass.

Shutdown Bypass

During plant cooldown, it is desirable to maintain the safety rods withdrawn to provide shutdown capabilities in the event of unusual positive reactivity additions (moderator dilution, etc.). However, if the safety rods are withdrawn too soon following reactor shutdown as RCS pressure is decreased, an RCS Low Pressure trip will occur at 1900 psig and the rods will re-insert into the core. To avoid this, the protection system allows the operator to bypass the low pressure trip and maintain shutdown capabilities.

During the cooldown and depressurization, the safety rods are inserted prior to the low pressure trip of 1900 psig. The RCS pressure is decreased to less than 1820 psig, then each RPS channel is placed in shutdown bypass.

In shutdown bypass, a normally closed contact opens and the operator closes the shutdown bypass key switch in each RPS channel. This action bypasses the RCS Low Pressure trip, Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE trip, Reactor Coolant Pump overpower/underpower trip, and the RCS Variable Low Pressure trip, and inserts a new RCS High Pressure, 1820 psig trip. The operator can now withdraw the safety rods for additional available reactivity insertion.

The insertion of the new high pressure trip performs two functions. First, with a trip setpoint of 1820 psig, the bistable prevents operation at normal system pressure, 2155 psig, with a portion of the RPS bypassed. The second function is to ensure that the bypass is removed prior to normal operation. When the RCS pressure is increased during

(continued)

BASES

BACKGROUND

Shutdown Bypass (continued)

a plant heatup, the safety rods are inserted prior to reaching 1820 psig. The shutdown bypass is removed, which returns the RPS to normal, and system pressure is increased to greater than 1900 psig. The safety rods can then be withdrawn and remain at the full out condition for the rest of the heatup.

In addition to the Shutdown Bypass RCS High Pressure trip, the nuclear overpower high flux trip setpoint is administratively reduced to 5% RTP while the RPS is in shutdown bypass. This provides a backup to the Shutdown Bypass RCS High Pressure trip and allows low temperature physics testing while preventing the generation of any significant amount of power.

Module Interlock and Test/Interlock Trip Relay

Each channel and each trip module is capable of being individually tested. When a module is placed into the test mode or is removed from the system, it causes the test/interlock trip relay to de-energize and to indicate an RPS channel trip. Under normal conditions, the channel to be tested is placed in bypass before a module is tested. This ensures the channel trip relay remains energized during testing and the channel does not trip.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Each of the analyzed accidents and transients can be detected by one or more RPS Functions. The accident analysis contained in Chapter 14 of the FSAR takes credit for most RPS trip Functions. Functions not specifically credited in the accident analysis were qualitatively credited in the safety evaluation report (SER) written for the CR-3 operating license. Functions not specifically credited include high RB pressure, high RCS temperature, main turbine trip, shutdown bypass-RCS pressure high, and loss of both main feedwater pumps.

The LCO requires all instrumentation performing an RPS Function to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

reliability of the affected Functions. Four channels of each RPS instrumentation Function listed in Table 3.3.1-1 shall be OPERABLE during the MODES and conditions specified to ensure that a reactor trip will be actuated if conditions require. Additionally, during shutdown bypass with any CRD trip breaker closed and the CRDCS capable of rod withdrawal, the applicable RPS Functions must also be OPERABLE. This ensures the capability to trip withdrawn CONTROL RODS at all times that rod motion is possible.

Required Actions allow maintenance (protection channel) bypass of individual channels, but the bypass activates interlocks that ensure only one channel can be bypassed at a time. Bypass effectively places the trip system in a two-out-of-three logic configuration that can still initiate a reactor trip, even with a coincident single failure within the system.

Only the Allowable Values are specified in Table 3.3.1-1. Nominal trip setpoints are specified in the plant specific setpoint calculations and procedures. The nominal setpoints are selected to ensure that the setpoint measured by CHANNEL FUNCTIONAL TESTS does not exceed the Allowable Value if the bistable is performing as required. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable provided that operation and testing are consistent with the assumptions of specific setpoint calculations. Each Allowable Value specified is more conservative than instrument uncertainties appropriate to the trip Function. The Allowable Values for bypass removal Functions are stated in the Applicable MODE or Other Specified Condition column of Table 3.3.1-1.

The safety analyses applicable to each RPS Function are discussed next.

1. Nuclear Overpower

a. Nuclear Overpower-High Setpoint

The Nuclear Overpower-High Setpoint trip initiates a reactor trip when the neutron power reaches a pre-defined setpoint corresponding to the design overpower limit. Because THERMAL POWER lags neutron power, tripping the reactor

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. RCS High Outlet Temperature (continued)

Allowable Value does not reflect errors induced by harsh environmental conditions that the equipment is expected to experience because the trip is not required to mitigate accidents that create harsh conditions in the RB.

3. RCS High Pressure

The RCS High Pressure trip functions in conjunction with the pressurizer and main steam safety valves to prevent RCS overpressurization, thereby protecting the RCS Pressure SL.

The RCS High Pressure trip has been credited in the accident analysis calculations for slow positive reactivity insertion transients (rod withdrawal accidents and moderator dilution) and loss of feedwater accidents. The rod withdrawal accidents cover a large spectrum of reactivity insertion rates and rod worths that exhibit slow and rapid rates of power increases. At high reactivity insertion rates, the Nuclear Overpower-High Setpoint trip LCO, and provides the primary protection. At low reactivity insertion rates, the RCS High Pressure trip provides the primary protection.

The Allowable Value is selected to ensure that the RCS Pressure SL is not challenged during steady state operation or slow power increasing transients. The Allowable Value does not reflect errors induced by harsh environmental conditions because the equipment is not required to mitigate accidents that create harsh conditions in the RB.

4. RCS Low Pressure

The RCS Low Pressure trip, in conjunction with the RCS High Outlet Temperature and Variable Low Pressure trips, provides protection for the DNBR SL. A trip is initiated whenever the system pressure approaches the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. RCS Low Pressure (continued)

conditions necessary for DNB. The RCS Low Pressure setpoint Allowable Value is selected to ensure that a reactor trip occurs before RCS pressure is reduced below the lowest point at which the RCS Variable Low Pressure trip is analyzed. The RCS Low Pressure trip provides protection for Primary system depressurization events and is credited in the accident analysis calculations for small break loss of coolant accidents (SBLOCAs). Consequently, harsh RB conditions created as a result of SBLOCAs can potentially affect performance of the RCS pressure sensors and transmitters. Therefore, degraded environmental conditions are considered in the Allowable Value determination.

5. RCS Variable Low Pressure

The RCS Variable Low Pressure trip, in conjunction with the RCS High Outlet Temperature and RCS Low Pressure trips, provide protection for the DNBR SL. The Allowable Value is selected such that a trip is initiated whenever RCS pressure and temperature approach the conditions necessary for DNB. The RCS Variable Low Pressure trip provides a varying low pressure trip based on the RCS High Outlet Temperature within the range specified by the RCS High Outlet Temperature and RCS Low Pressure trips.

The RCS Variable Low Pressure trip is not credited in the safety analysis; therefore, determination of the setpoint Allowable Value does not account for errors induced by a harsh RB environment.

6. Reactor Building High Pressure

The Reactor Building High Pressure trip provides an early indication of a high energy line break (HELB) inside the RB. By detecting changes in the RB pressure, the RPS can provide a reactor trip before the other RCS parameters have varied significantly; thus, minimizing accident consequences. This trip Function also provides a backup to RPS trip strings exposed to an RB HELB environment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Reactor Building High Pressure (continued)

The Allowable Value for RB High Pressure trip is at the lowest value consistent with avoiding spurious trips during normal operation. The electronic components of the RB High Pressure trip are located in an area outside the RB and are not exposed to high temperature steam environments during a LOCA. However, the components would be potentially exposed to high radiation levels. Therefore, the determination of the setpoint Allowable Value accounts for errors induced by the high radiation.

7. Reactor Coolant Pump Power Monitors

The Reactor Coolant Pump Power Monitor (RCPPM) trip provides protection for changes in the reactor coolant flow due to the loss of multiple RCPs. Because the flow reduction lags loss of power indications due to the inertia of the RCPs, the trip initiates protective action earlier than a trip based on a measured flow signal.

The trip also prevents single loop operation (operation with both pumps in an RCS loop tripped). Under these conditions, core flow and core fluid mixing are insufficient for adequate heat transfer.

The RCPPM trip has been credited in the accident analysis calculations for the loss of four RCPs. The monitors were added as part of the power level upgrade (2452 to 2544 MW_{th}) to provide DNB protection at greater than 97% RTP. Analyses has shown this trip Function is not necessary when conditions are such that THERMAL POWER is less than 2475 MW_{th} and four RCPs are in operation (Ref. 8).

The Allowable Value for the Reactor Coolant Pump to Power trip setpoint is selected to prevent normal power operation unless at least three RCPs are operating. RCP status is monitored by two power transducers on each pump. The allowable values for the Reactor Coolant Pump Power Monitors are selected to trip the reactor if more than one RCP is drawing ≥ 14,400 kW or ≤ 1152 kW. The overpower setpoint is selected low enough to detect locked rotor conditions (although credit is not allowed for this capability) but high enough to avoid a spurious trip due to the current associated with start of an RCP. The underpower Allowable Value is selected to reliably trip on loss of voltage to the RCPs. The RCPPM setpoints do not account for instrumentation errors caused by harsh environments because the trip Function is not required to respond to events that could create harsh environments around the equipment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7. Reactor Coolant Pump Power Monitors (continued)

There are two pump power monitors provided for each RCP. Both monitors are required to satisfy the instrumentation channel requirements of this LCO.

The RPS RCPPMs act as the sensors for the EFIC (Emergency Feedwater Initiation and Control System) RCP Status function by providing a loss of RCP indication to each EFIC channel. When a minimum of two EFIC channels recognize a loss of all RCPs, EFIC will automatically actuate EFW (Emergency Feedwater System) and control level to natural circulation level in the OTSG (Once Through Steam Generator).

8. Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE

The Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE trip provides steady state protection for the power imbalance SLs. A reactor trip is initiated when neutron power AXIAL POWER IMBALANCE, and reactor coolant flow conditions indicate an approach to DNB or fuel centerline melt limits.

This trip supplements the protection provided by the Reactor Coolant Pump Power trip, through the power to flow ratio, for loss of reactor coolant flow events. The power to flow ratio provides direct protection for the DNBR SL for the loss of a single RCP and for locked RCP rotor accidents. The imbalance portion of the trip is credited for steady state protection only.

The power to flow ratio of the Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE trip also provides steady state protection to prevent reactor power from exceeding the allowable power during three pump operation. Thus, the power to flow ratio prevents overpower conditions similar to the Nuclear Overpower trip. This protection ensures that during reduced flow conditions the core power is maintained below that required to initiate DNB.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8. Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE (continued)

The Allowable Value is selected to ensure that a trip occurs when the core power, axial power peaking, and reactor coolant flow conditions indicate an approach to DNB or fuel centerline melt limits. By measuring reactor coolant flow and by tripping only when conditions begin to approach an SL, 3 pump operation can be justified. The Allowable Value for this Function is contained in the COLR due to the cycle-specific nature of the limit.

The following instruments providing reactor coolant flow measurement would be rendered non-functional due the dynamic effects of a LOCA:

- RC-14A-DPT2 and RC-14A-DPT3

These instruments are differential pressure transmitters that develop two of the four RCS flow signals for the "A" loop of the nuclear overpower trip. A rupture of the pressurizer surge line would result in jet impingement on the instrument tubing for RC-14A-DPT2 and RC-14A-DPT3, causing its failure. A failure of the line on either the high pressure side or the lines on both sides would result in zero flow indicated on two of the channels on the loop and a subsequent reactor trip due to an excessive power to flow ratio. Consideration of a single failure in one of the two remaining channels would not influence the outcome in this scenario. On the other hand, a failure of the low pressure side would result in maximum indicated flow for the loop in two of the four channels. Indication of maximum flow is not indicative of any operational problem and is contradictory to the actual RCS condition of a loss of flow from the system. In this instance, consideration of a single failure in one of the two remaining channels is problematic since achieving a two-out-of-four RCS low flow trip would not be possible. However, the RPS trip credited in the accident analysis calculations for small break LOCAs is the RCS low pressure trip, which is not impacted by a surge line rupture. In addition, the reactor building high pressure trip, which provides an early indication of a high energy line break inside the reactor building and serves as a backup to the RCS low pressure trip, would also be available after a surge line rupture. Therefore, a consequential failure of RC-14A-DPT2 and RC-14A-DPT3 due to a pressurizer surge line rupture is acceptable since they are not required to perform any protective function for this LOCA.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

9. Main Turbine Trip (Control Oil Pressure)

The Main Turbine Trip Function provides an early reactor trip in anticipation of the loss of heat sink associated with a turbine trip. The Main Turbine Trip Function was added to B&W plants in accordance with NUREG-0737 (Ref. 4) following the Three Mile Island Unit 2 accident. The trip lowers the probability of an RCS power operated relief valve (PORV) actuation for turbine trip events. This trip is activated at higher power levels, thereby limiting the range through which the Integrated Control System must provide an automatic runback on a turbine trip.

Each of the four turbine oil pressure switches provides input to an associated RPS channel through buffers that continuously monitor the status of the contacts. Failure of an individual pressure switch affects only the associated RPS channel.

For the Main Turbine Trip (Control Oil Pressure) bistable, the Allowable Value of 45 psig was selected to provide a trip whenever turbine control oil pressure drops below the normal operating range. To ensure that the trip is enabled as required by the LCO, an automatic bypass at reactor power Allowable Value of 45% RTP is provided. The turbine trip is not required to protect against events that create a harsh environment in the turbine building. Therefore, errors induced by harsh environments are not included in the determination of the setpoint Allowable Value.

10. Loss of Main Feedwater Pumps (Control Oil Pressure)

The Loss of Main Feedwater Pumps (Control Oil Pressure) trip Function provides an early reactor trip in anticipation of the loss of heat sink associated with a LOFW event. This trip was added in accordance with NUREG-0737 (Ref. 4), following the Three Mile Island Unit 2 accident. This trip provides a reactor trip at high power levels following a LOFW to minimize challenges to the PORV.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

10. Loss of Main Feedwater Pumps (Control Oil Pressure) (continued)

For the feedwater pump control oil pressure bistable, the Allowable Value of 55 psig is selected to provide a trip whenever feedwater pump control oil pressure drops below the normal operating range. To ensure that the trip is enabled as required by the LCO, the reactor power bypass is set with an Allowable Value of 20% RTP. The Loss of Main Feedwater Pumps (Control Oil Pressure) trip is not required to protect against events that can create a harsh environment in the turbine building. Therefore, errors caused by harsh environments are not included in the determination of the setpoint Allowable Value.

11. Shutdown Bypass RCS High Pressure

The RPS Shutdown Bypass RCS High Pressure TRIP is provided to allow for withdrawing the CONTROL RODS prior to reaching the normal RCS Low Pressure trip setpoint. The shutdown bypass provides trip protection during deboration and RCS heatup by allowing the operator to withdraw the safety rod groups. This makes additional negative reactivity readily available to terminate inadvertent reactivity excursions. Use of the shutdown bypass trip requires that the nuclear overpower trip setpoint be administratively reduced to ≤ 5% RTP. The Shutdown Bypass RCS High Pressure trip forces a reactor trip to occur whenever the plant switches from power operation to shutdown bypass or vice versa. This ensures that all CONTROL RODS are inserted and the flux distribution is known before reactor startup can begin. The operator is required to remove the shutdown bypass, reset the Nuclear Overpower-High Power trip setpoint, and again withdraw the safety rod groups before proceeding with startup.

FSAR, Chapter 14, (Ref. 2), accident analysis does not address events that occur during shutdown bypass operation, because the consequences of these events are assumed to be enveloped by the MODE 1 events that are presented.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

11. Shutdown Bypass RCS High Pressure (continued)

During shutdown bypass operation with the Shutdown Bypass RCS High Pressure trip active with a setpoint of ≤ 1820 psig and the Nuclear Overpower-Low Setpoint set at or below 5% RTP, the trips listed below can be bypassed. Under these conditions, the Shutdown Bypass RCS High Pressure trip and the Nuclear Overpower-Low Setpoint trip prevent conditions from reaching a point where actuation of these Functions would be required.

1.a Nuclear Overpower-High Setpoint;

4. RCS Low Pressure;

5. RCS Variable Low Pressure;

7. Reactor Coolant Pump Power Monitors; and

8. Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE.

The Shutdown Bypass RCS High Pressure Function's Allowable Value is selected to ensure a trip occurs before producing THERMAL POWER.

The RPS satisfies Criterion 3 of the NRC Policy Statement.

In MODES 1 and 2, the following trips shall be OPERABLE. These trips are designed to rapidly make the reactor subcritical in order to protect the SLs during AOOs and to function along with the ESAS to provide acceptable consequences during accidents.

1.a Nuclear Overpower-High Setpoint;

2. RCS High Outlet Temperature;

3. RCS High Pressure;

4. RCS Low Pressure;

5. RCS Variable Low Pressure;

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

11. Shutdown Bypass RCS High Pressure (continued)

7. Reactor Coolant Pump Over/Under Power; and

8. Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE.

Functions 1, 4, 5, 7, and 8 may be bypassed in MODE 2 or below (higher numerical MODE) when RCS pressure is below 1820 psig, provided the Shutdown Bypass RCS High Pressure and the Nuclear Overpower-Low setpoint trip are placed in operation. Under these conditions, the Shutdown Bypass RCS High Pressure trip and the Nuclear Overpower-Low setpoint trip prevent conditions from reaching a point where actuation of these Functions is necessary.

Two other Functions are required to be OPERABLE during portions of MODE 1. These are the Main Turbine Trip (Control Oil Pressure) and the Loss of Main Feedwater Pumps (Control Oil Pressure) trip. These Functions are required to be OPERABLE above 45% RTP and 20% RTP, respectively. Analyses presented in BAW-1893 (Ref. 5) showed that for operation below these power levels, these trips are not necessary to minimize challenges to the PORVs as required by NUREG-0737 (Ref. 4).

Because the only safety function of the RPS is to interrupt power to the CONTROL RODS, the RPS is not required to be OPERABLE in MODE 3, 4, or 5 if the reactor trip breakers are open, or the CRDCS is incapable of rod withdrawal.

Similarly, the RPS is not required to be OPERABLE in MODE 6 when the CONTROL RODS are decoupled from the CRDs. However, in MODE 2, 3, 4, or 5, the Shutdown Bypass RCS High Pressure and Nuclear Overpower-Low Setpoint trip Functions are required to be OPERABLE if the CRD trip breakers are closed and the CRDCS is capable of rod withdrawal. Under these conditions, the Shutdown Bypass RCS High Pressure and Nuclear Overpower-Low setpoint trips are sufficient to prevent an approach to conditions that could challenge SLs.

(continued)

BASES (continued)

ACTIONS

Conditions A, B, and D are applicable to all RPS protection Functions. If a channel's trip setpoint is found nonconservative with respect to the required Allowable Value in Table 3.3.1-1, or any individual component in the trip string is found inoperable (with the exception of the RCPPM), the channel must be declared inoperable. Conditions C and E address the appropriate ACTIONS for an inoperable RCPPM from the sensor to the output of the watt transducer. Inoperable components downstream of the watt transducers are addressed by Conditions A and B.

A.1

If one or more Functions in an RPS channel become inoperable, the affected channel must be placed in bypass or trip within 1 hour. If the channel is bypassed, the RPS is placed in a two-out-of-three logic configuration and the bypass of any other channel is prevented. In this configuration, the RPS can still perform its safety function given a single failure of any other channel. Operation in the two-out-of-three configuration may continue indefinitely based on the NRC SER for BAW-10167, Supplement 2 (Ref. 6). In this configuration, the RPS is capable of performing its trip Function in the presence of any single random failure. Alternatively, the inoperable channel can be placed in trip. Tripping the affected protection channel places the RPS in a one-out-of-three configuration.

The 1 hour Completion Time is of adequate duration to perform Required Action A.1. Thus, the 1 hour Completion Time is based on engineering judgment.

B.1 and B.2

If one or more Functions in two channels become inoperable, one of the two inoperable channels must be placed in trip and the other in bypass. These Required Actions place all RPS Functions in a one-out-of-two logic configuration and prevent bypass of a second channel. In this configuration, the RPS can still perform its safety functions in the presence of a single failure of any channel. The 1 hour Completion Time is of adequate duration to perform Required Action B.1 and Required Action B.2. Thus, the 1 hour Completion Time is based on engineering judgment.

(continued)

BASES

ACTIONS (continued)

C.1

If one or both RCPPMs associated with a single RCP are inoperable, the RCPPM must be placed in the trip condition within 4 hours. Placing one of the RCPPMs for the pump in the tripped condition restores the single failure aspect of the design of the Function. This ACTION also places the RPS Function in a condition where only one additional RCPPM associated with another RCP need indicate a loss of its associated RCP to initiate a reactor trip. Since each RCPPM provides input to all four RPS and EFIC channels, care must be exercised when surveillance testing RCPPM coincident with operation in this Condition. The 4 hour Completion Time is adequate to perform Required Action C.1 and is acceptable based upon engineering judgment.

If a single RCPPM for a single RCP is inoperable and is not tripped, neither the RPS nor the EFIC safety function is lost. The exception to LCO 3.0.2 allowed by LCO 3.0.6 may be applied for the Completion Time. If both RCPPMs for a single RCP are inoperable and neither is tripped, the RCP status safety function associated with the EFIC Instrumentation Improved Technical Specification is lost for all four channels. The exception to LCO 3.0.2 allowed by LCO 3.0.6 must not be applied.

D.1 and D.2

Required Action D.1 directs entry into the appropriate Function-dependent Condition referenced in Table 3.3.1-1. Whenever a Required Action of Condition A or B, and the associated Completion Time are not met, Condition D directs the operator to the Condition containing the appropriate ACTIONS.

E.1.1, E.1.2, and E.2

If the Required Actions and associated Completion Times of Condition C are not met, the plant must be placed in a MODE or condition in which the RCPPM are not required to be OPERABLE. To achieve this status, four reactor coolant pumps must be verified to be in operation and THERMAL POWER must be reduced to less than 2475 MW_{th}, within one hour. The Required Actions are based upon analysis (Ref. 8) which demonstrates that the Nuclear Overpower RCS Flow and Measured AXIAL POWER IMBALANCE RPS Function provides adequate protection of DNBR limits for loss of coolant flow accidents postulated to occur under these conditions. Thus, the RCPPM Function is not required. Similar analysis for three RCP operation was never approved. The allowed Completion Times of one hour are reasonable, based on operating experience, to perform the specified Required Actions.

(continued)

BASES

ACTIONS

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

As an alternative to Required Action E.1.1 and Required Action E.1.2, Condition F may be entered within one hour. This results in placing the plant in MODE 3 and opening the CRD trip breakers within 6 hours. This is the default Condition in the event the Required Actions for an inoperable RPS RCPPM Function channel cannot be completed in the specified Completion Time. As such, this ACTION is conservative. Again, the allowed Completion Time of one hour is reasonable, based on engineering judgment, to perform the specified Required Action.

F.1 and F.2

If the Required Action and associated Completion Time of Condition A or B are not met and Table 3.3.1-1 directs entry into Condition F, the plant must be placed in a MODE in which the specified RPS trip Functions are not required to be OPERABLE. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and to open all CRD trip breakers without challenging plant systems.

G.1

If the Required Action and associated Completion Time of Condition A or B are not met and Table 3.3.1-1 directs entry into Condition G, the plant must be placed in a MODE in which the specified RPS trip Functions are not required to be OPERABLE. To achieve this status, all CRD trip breakers must be opened. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to open CRD trip breakers without challenging plant systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

Surveillance is required only when reactor power is ≥ 15% RTP and that 24 hours is allowed for performing the first Surveillance after reaching 15% RTP. This SR 3.0.4 type allowance is provided since at lower power levels, calorimetric data tends to be inaccurate.

The power range channel's output must be adjusted consistent with the calorimetric results if the calorimetric exceeds the power range channel's output by > 2% RTP. The value of 2% is consistent with the value assumed in the safety analyses of FSAR, Chapter 14 (Ref. 2) accidents. These checks and, if necessary, the adjustment of the power range channels ensure that channel accuracy is maintained within the error margins assumed in the analysis. The 24 hour Frequency is adequate, based on plant operating experience, which demonstrates the change in the difference between the power range indication and the calorimetric results rarely exceeds a small fraction of 2% in any 24 hour period. Furthermore, the control room operators monitor redundant indications and alarms to detect deviations in channel outputs.

SR 3.3.1.3

A comparison of power range nuclear instrumentation channels (excores) against incore detectors shall be performed at a 31 day Frequency when reactor power is ≥ 30% RTP. A Note clarifies that 24 hours is allowed for performing the first Surveillance after reaching 30% RTP. If the absolute difference between the power range and incore measurements is ≥ 2.5% RTP, the trip Functions which receive an input from the NI are not considered inoperable, but a CHANNEL CALIBRATION that adjusts the measured imbalance to agree with the incore measurements is necessary. If the power range channel cannot be properly recalibrated, the channel is declared inoperable. The calculation of the Allowable Value envelope assumes a difference in out of core to incore measurements of 2.5%. Additional inaccuracies beyond those that are measured are also included in the setpoint envelope calculation. The 31 day Frequency is adequate, considering that long term drift of the excore linear amplifiers is

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.3 (continued)

small and depletion of the detectors is slow. Also, the excore readings are a strong function of the power produced in the peripheral fuel bundles, and do not represent an integrated reading across the core. The slow changes in neutron flux during the fuel cycle can also be detected at this interval.

SR 3.3.1.4

A CHANNEL FUNCTIONAL TEST is performed on each required RPS channel to ensure that the entire channel will perform the intended function. Setpoints must be found within the Allowable Values specified in Table 3.3.1-1.

The Frequency of 45 days on a STAGGERED TEST BASIS results in each channel being tested every 6 months and is based on the results of the analysis approved in Reference 7. That analysis indicates the RPS retains a high level of reliability for this test interval.

SR 3.3.1.5

This SR is the performance of a CHANNEL CALIBRATION of Functions utilizing an NI signal in the trip logic. This CHANNEL CALIBRATION normalizes the power range channel output to the calorimetric coincident with the imbalance output being normalized to the imbalance condition predicted by the incore neutron detector system.

The calibration for both imbalance and total power is integrated in the power imbalance detector calibration procedure. Operating experience has shown the reliability of the trip string is acceptable when calibrated on a 92 day interval. Thus, the Frequency is based on engineering judgment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.5 (continued)

This Surveillance is modified by two Notes. The first clarifies that neutron detectors and RC flow sensors (tubes) are not required to be tested as part of this Surveillance. In the case of the neutron detectors, there is no adjustment that can be made to the detectors. Furthermore, adjustment of the detectors is unnecessary because they are passive devices with minimal drift. Slow changes in detector sensitivity are compensated for by performing the daily calorimetric calibration and the monthly axial channel calibration. RCS flow detectors are excluded from this SR, but are surveilled as part of SR 3.3.1.6 on a refueling basis. This is based on their inaccessibility during power operations. The second note clarifies that the bypass function associated with the test Functions need only be performed once per fuel cycle. This is consistent with the definition of CHANNEL CALIBRATION.

SR 3.3.1.6

The CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. The 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 drift to ensure that the instrument channel remains operational between successive tests. The 24 month Frequency is based on the results of comprehensive instrument uncertainty calculations that accommodate 30 months of drift as approved in Amendment 152 (Ref. 9).

A Note to the Surveillance indicates that neutron detectors and RCPPM current and voltage sensors are excluded from CHANNEL CALIBRATION. In the case of the neutron detectors, this Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response. RCPPM current and voltage sensors are excluded due to the fact no adjustments can be made to these sensors.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.7

This SR verifies individual channel actuation response times are less than or equal to the maximum values assumed in the accident analysis. Individual component response times are not modeled in the analyses. The analyses model the overall, or total, elapsed time from the point at which the parameter exceeds the analytical limit at the sensor to the point of rod insertion. Response time testing acceptance criteria are included in Reference 1.

A Note to the Surveillance indicates that neutron detectors and RCPPM current and voltage sensors and the watt transducer are excluded from RPS RESPONSE TIME testing. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response.

Response time tests are conducted on an 24 month STAGGERED TEST BASIS. This results in testing all four RPS channels every 96 months. The 96 month Frequency is based on operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

REFERENCES

1. FSAR, Chapter 7.
2. FSAR, Chapter 14.
3. 10 CFR 50.49.
4. NUREG-0737, November 1979.
5. BAW-1893.
6. NRC SER for BAW-10167, Supplement 2, July 8, 1992.
7. NRC SER for BAW-10167A and Supplement 1, December 5, 1988.
8. Amendment No. 56 to the CR-3 Technical Specifications, dated July 16, 1982.
9. Amendment No. 152 to the CR-3 Technical Specifications dated February 13, 1996.

BASES

ACTIONS (continued)

E.1 and E.2

If the Required Actions of Condition A, B, or C are not met within the associated Completion Time while the plant is in MODE 4 or 5, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, all CRD trip breakers must be opened or all power to the CRDCS removed within 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to open all CRD trip breakers or remove all power to the CRDCS without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

SR 3.3.4.1 is a CHANNEL FUNCTIONAL TEST to the CRD trip devices once every 31 days. This test verifies the OPERABILITY of the trip devices by actuation of the end devices. Also, this test independently verifies the undervoltage and shunt trip mechanisms of the CRD trip breakers. The Frequency of 31 days is based on operating experience, which has demonstrated that failure of more than one trip device in any 31 day interval is unlikely.

REFERENCES

1. FSAR, Chapter 7.

B 3.3 INSTRUMENTATION

B 3.3.5 Engineered Safeguards Actuation System (ESAS) Instrumentation

BASES

BACKGROUND

The ESAS initiates Engineered Safeguards (ES) Systems, based on the values of selected plant parameters, to protect core design and reactor coolant pressure boundary limits and to mitigate accidents.

ESAS actuates the following:

a. High Pressure Injection (HPI);

b. Low Pressure Injection (LPI);

c. Reactor Building (RB) Isolation and Cooling;

d. RB Spray;

e. Emergency Diesel Generator (EDG) Start; and

f. Control complex normal recirculation.

ESAS also provides an "A" train and "B" train HPI actuation signal to the EFIC Channel A and B Trip Modules to initiate emergency feedwater when both ESAS HPI trains are actuated. In addition, the LPI pump is prohibited from starting on a RB isolation concurrent with a loss of offsite power.

The ESAS operates in a distributed manner to initiate the appropriate systems. The ESAS does this by monitoring RCS pressure actuation parameters in each of three channels and RB pressure actuation in each of six channels (3 per actuation train). Once the setpoint for actuation is reached, the signal is transmitted to automatic actuation logics, which perform the two-out-of-three logic for actuation of each end device. However, all automatic actuation logics receive signals from the same channels for each parameter.

Four parameters are used for actuation:

a. Low Reactor Coolant System (RCS) Pressure;

(continued)

BASES

BACKGROUND (continued)

b. Low-Low RCS Pressure;

c. High RB Pressure; and

d. High High RB Pressure.

This LCO covers only the instrumentation channels that monitor these parameters. These channels include all intervening equipment from (including) the sensor, to (not including) the actuation logic. LCO 3.3.6, "Engineered Safeguards Actuation System (ESAS) Manual Initiation," and LCO 3.3.7, "Engineered Safeguards Actuation System (ESAS) Automatic Actuation Logic," provide requirements on the manual initiation and automatic actuation logic Functions.

The ESAS RCS Pressure Parameters consists of three analog instrumentation channels. The digital portion of the string (from the output of the bistable on) is essentially six channels. The ESAS RB Pressure Parameters are six channels of instrumentation throughout the entire trip string. Each channel provides input to logics that initiate equipment with a two-out-of-three logic in each train. Each protection channel includes bistable inputs from one instrumentation channel of Low RCS Pressure and Low-Low RCS Pressure and pressure switch inputs from three channels of High RB Pressure and High-High RB Pressure. Automatic actuation logics combine the three protection channel trips in each train to actuate the individual Engineered Safeguards (ES) components needed to initiate each ES System Function. Figure 7-5 of the FSAR, (Ref. 1), illustrates how instrumentation channel trips combine to cause protection channel trips.

The RCS pressure sensors are common to both actuation trains. Separate RB pressure sensors are used for the high and high high pressure Functions in each train, and separate sensors are used for each train.

FSAR Table 7-3 identifies the measurement channels used for ES actuation and the Function actuated by each.

The ES equipment is divided between the two redundant actuation trains A and B. The division of the equipment between the two actuation trains is based on the equipment redundancy and function and is accomplished in such a manner that the failure of one of the actuation channels and the

(continued)

BASES

BACKGROUND (continued)

related safeguards equipment will not inhibit the overall ES Functions. Where a motor operated or a solenoid operated valve is driven by either of two matrices, one is from actuation train A and one from actuation train B. Redundant ES pumps are controlled from separate and independent actuation channels.

Engineered Safety Feature Actuation System Bypasses

No provisions are made for maintenance bypass of ESAS instrumentation channels. Operational bypasses are provided, as discussed below, to allow accident recovery actions to continue and, to allow plant cooldown without spurious ESAS actuation.

The ESAS RCS pressure instrumentation channels include permissive bistables that allow manual bypass when reactor pressure is below the point at which the low and low low pressure trips are required to be OPERABLE. Once permissive conditions are sensed, the RCS pressure trips may be manually bypassed. Bypasses are automatically removed when bypass permissive conditions are no longer applicable.

No more than two (of the three) High RB Pressure channels may be manually bypassed after an actuation. The manual bypass allows operators to take manual control of ES Functions after initiation to allow recovery actions.

Reactor Coolant System Pressure

RCS pressure is monitored by three independent pressure transmitters located in the RB. These transmitters are separate from the transmitters that provide an input to the Reactor Protection System (RPS). Each of the pressure signals generated by these transmitters is monitored by four bistables to provide two trip signals, at 1625 psig and 500 psig, and two bypass permissive signals, at 1800 psig and 900 psig.

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BASES

BACKGROUND

Reactor Coolant System Pressure (continued)

The outputs of the three channels trip bistables, associated with the low RCS pressure (1625 psig) actuate bistable trip auxiliary relays in two sets (actuation trains A and B) of identical and independent trains. The two HPI trains each use three logic channels arranged in two-out-of-three coincidence networks. The outputs of the three bistables associated with the Low Low RCS Pressure (500 psig) actuate bistable trip auxiliary relays in two sets (actuation trains A and B) of identical and independent trains. The two LPI trains each use three logic channels arranged in two-out-of-three coincidence networks for LPI Actuation. The outputs of the three Low Low RCS Pressure bistables also trip the automatic actuation relays, via a LPI bistable trip auxiliary relay, in the corresponding HPI train as previously described.

Reactor Building Pressure

ESAS RB pressure signal information is provided by 12 pressure switches. Six pressure switches are used for the High RB Pressure Parameter, and six pressure switches are used for the High-High RB Pressure Parameter.

The output contacts of six High RB Pressure switches are used in two sets of identical and independent actuation trains. These two trains each use three logic channels. The outputs of these channels are used in two-out-of-three coincidence networks. The output contacts of the six RB pressure switches also trip, via a pressure switch trip auxiliary relay, the automatic actuation relays in the corresponding HPI and LPI trains as previously described.

The output contacts of six High High RB Pressure switches are used in two sets of identical and independent actuation trains. The outputs of the High High RB Pressure switches are used in two-out-of-three coincident networks for RB Spray Actuation. The two-out-of-three logic associated with each RB Spray train actuates spray pump operation when the High-High RB signal and the HPI signal are coincident in that train.

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BASES

APPLICABLE SAFETY ANALYSES

Accident analyses rely on automatic ESAS actuation for protection of the core temperature and containment pressure limits and for limiting off site dose levels following an accident. These include LOCA, SLB, and feedwater line break events that result in RCS inventory reduction or severe loss of RCS cooling.

The following ESAS Functions are assumed to operate to mitigate design basis accidents.

High Pressure Injection

The ESAS actuation of HPI has been assumed for core cooling in the small break LOCA analysis and is credited in the SLB analysis for the purposes of adding boron and negative reactivity. HPI is also credited in the Steam Generator Tube Rupture (SGTR) accident analysis.

Manual actuation of HPI may be relied upon whenever ESAS signal are bypassed during heatup or cooldown, or when in Mode 4.

Low Pressure Injection

The ESAS actuation of LPI has been assumed for large break LOCAs.

Manual actuation of HPI may be relied upon whenever ESAS signal are bypassed during heatup or cooldown, or when in Mode 4.

Reactor Building Spray, Reactor Building Cooling, and Reactor Building Isolation

ESAS actuation of the RB coolers and RB Spray is credited in RB analysis for LOCAs, both for RB performance and equipment environmental qualification pressure and temperature envelope definition. Accident dose calculations credit RB Isolation and RB Spray.

Emergency Diesel Generator Start

The ESAS initiated EDG Start has been assumed in the LOCA analysis to ensure that emergency power is available throughout the limiting LOCA scenarios.

The large break LOCA analyses assume a conservative 35 second delay time for the actuation of LPI in FSAR, Chapter 6, (Ref. 3). The small break LOCA analyses assume a conservative 67 second delay time for the actuation of HPI.

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BASES

APPLICABLE SAFETY ANALYSES

Emergency Diesel Generator Start (continued)

These delay times include allowances for EDG starting, EDG output breaker closure, EDG voltage recovery, EDG loading, Emergency Core Cooling Systems (ECCS) pump starts, and valve openings. Similarly, RB Isolation and Cooling, and RB Spray have been analyzed with delays appropriate for the entire system analyzed. Values used in the analysis are 25 seconds for RB Cooling, 60 seconds for RB Isolation, and 90 seconds for RB Spray.

ESAS instrumentation channels satisfy Criterion 3 of the NRC Policy Statement.

LCO

The LCO requires the specified ESAS instrumentation for each Parameter in Table 3.3.5-1 to be OPERABLE. Failure of any instrument renders the affected channel inoperable and reduces the margin to meeting the single failure criteria for the affected Functions.

Three channels of RCS Pressure ESAS instrumentation and two channels of ESAS RB pressure instrumentation in each actuation train shall be OPERABLE to ensure that a single failure in one channel will not result in loss of the ability to automatically actuate the required safety function.

The bases for the LCO on ESAS Parameters include the following.

Reactor Coolant System Pressure

Three channels each of RCS Pressure-Low and RCS Pressure-Low-Low are required to be OPERABLE. Each channel includes a sensor, trip bistable, bypass bistable, bypass relays, and bistable trip auxiliary relays. In addition, each RCS Pressure-Low channel also includes time delay auxiliary relays. The analog portion of each pressure channel is common to both trains of both RCS Pressure Parameters. Therefore, failure of one analog channel renders one channel of the low pressure and low low pressure Functions in each train inoperable. The bistable portions of the channels are Function and train specific.

(continued)

BASES

LCO

Reactor Coolant System Pressure (continued)

Therefore, a bistable failure renders only one Function in one train inoperable. Failure of a bypass bistable or bypass circuitry, such that a trip channel cannot be bypassed, does not render the channel inoperable. Bistable trip auxiliary relays and auxiliary time delay relays are train specific but may be shared among Parameters. Therefore, bistable trip auxiliary or auxiliary time delay relay failure has the potential to render all affected Functions in one train inoperable.

1. Reactor Coolant System Pressure-Low Setpoint

The RCS Pressure-Low Setpoint is based on HPI actuation for small break LOCAs. The setpoint ensures that the HPI will be actuated at a pressure greater than or equal to the value assumed in accident analyses plus the instrument uncertainties.

2. Reactor Coolant System Pressure-Low Low Setpoint

The RCS Pressure-Low Low Setpoint LPI actuation occurs in sufficient time to ensure LPI flow prior to the emptying of the core flood tanks during a large break LOCA. The Allowable Value of ≥ 500 psig ensures sufficient overlap of the core flood tank flow and the LPI flow to keep the reactor vessel downcomer full during a large break LOCA.

Reactor Building Pressure

Two channels each of RB Pressure-High and RB Pressure-High High are required to be OPERABLE in each train. Each channel includes a pressure switch, bypass relays, and pressure switch trip auxiliary relays. An inoperable pressure switch renders only one channel in one train inoperable. Pressure switch trip auxiliary relays are train specific but may be shared among Parameters. Therefore, trip relay failure has the potential to render all affected Functions in one train inoperable.

(continued)

BASES

LCO (continued)

1. Reactor Building Pressure-High Setpoint

The RB Pressure-High Setpoint Allowable Value ≤ 4 psig was selected to be low enough to detect a rise in RB Pressure that would occur due to a small break LOCA, thus ensuring that the RB high pressure actuation of the safety systems will occur for a wide spectrum of break sizes. The trip setpoint also causes the RB coolers to shift to low speed (performed as part of the HPI logic) to prevent damage to the cooler fans due to the increase in the density of the air steam mixture present in the containment following a LOCA.

2. Reactor Building Pressure-High High Setpoint

The RB Pressure-High High Setpoint Allowable Value ≤ 30 psig was chosen to be high enough to avoid actuation during an SLB, but also low enough to ensure a timely actuation during a large break LOCA.

APPLICABILITY

The ESAS instrumentation for each Parameter is required to be OPERABLE during the following MODES and specified conditions.

1. Reactor Coolant System Pressure-Low Setpoint

The RCS Pressure-Low Setpoint actuation Parameter shall be OPERABLE during operation above 1800 psig. This ensures the capability to automatically actuate safety systems and components during conditions indicative of a LOCA or SLB. Below 1800 psig, the low RCS Pressure actuation Parameter can be bypassed to avoid actuation during normal cooldown when safety system actuations are not required.

The allowance for the bypass is consistent with the plant transition to a lower energy state, providing greater margins to core and containment limits. The response to any event, given that the reactor is already shut down, will be less severe and allows sufficient time for operator action to provide manual safety system actuations. This is even more appropriate during plant heatup from an outage when the RCS energy content is low.

(continued)

BASES

APPLICABILITY

1. Reactor Coolant System Pressure-Low Setpoint (continued)

To ensure the RCS Pressure-Low trip is not bypassed when required to be OPERABLE by the safety analysis, each channel's bypass removal bistable must be set with a setpoint of ≤ 1800 psig. The bypass removal does not need to function for accidents initiated from RCS Pressures below the bypass removal setpoint.

2. Reactor Coolant System Pressure-Low Low Setpoint

The RCS Pressure-Low Low Setpoint actuation Parameter shall be OPERABLE during operation above 900 psig. This ensures the capability to automatically actuate safety systems and components during conditions indicative of a LOCA. Below 900 psig, the low low RCS Pressure actuation Parameter can be bypassed to avoid actuation during normal plant cooldown.

The allowance for the bypass is consistent with plant transition to a lower energy state, providing greater margins to core and containment limits. The response to any event, given that the reactor is already tripped, will be less severe and allows sufficient time for operator action to provide manual safety system actuations. This is even more appropriate during heatup from an outage when the RCS energy content is low.

To ensure the RCS Pressure-Low Low trip is not bypassed when assumed OPERABLE by the safety analysis, each channel's bypass removal bistable must be set with a setpoint of ≤ 900 psig. The bypass removal does not need to function for accidents initiated by RCS Pressure below the bypass removal setpoint.

(continued)

BASES

APPLICABILITY (continued)

3,4. Reactor Building Pressure-High and Reactor Building Pressure-High High Setpoints

The RB Pressure-High and RB Pressure-High High actuation Functions of ESAS shall be OPERABLE in MODES 1, 2, and 3. In MODES 4, 5 and 6, there is insufficient energy in the primary and secondary systems to raise containment pressure to either the RB Pressure-High or RB Pressure-High High Setpoints in the event of a line break. Furthermore, there is adequate time for the operator to evaluate plant conditions and manually respond.

ACTIONS

Required Actions A and B apply to all ESAS instrumentation Parameters listed in Table 3.3.5-1.

A Note has been added to the ACTIONS indicating separate Condition entry is allowed for each Parameter.

A.1

Condition A applies when one instrumentation channel in one or more RCS Pressure Parameters becomes inoperable. If one ESAS channel is inoperable, placing it in a tripped condition leaves the system in a one-out-of-two condition for actuation. Thus, if another channel were to fail, the ESAS instrumentation could still perform its actuation functions. For RCS Pressure-Low, this action is completed when all of the affected bistable trip auxiliary relays and time delay auxiliary relays are tripped. For RCS Pressure-Low Low, this action is completed when all of the affected bistable trip auxiliary relays are tripped. This is normally accomplished by tripping the affected bistable.

The 1 hour Completion Time is based on engineering judgment and is sufficient time to perform the Required Action.

(continued)

BASES

ACTIONS (continued)

B.1

Condition B applies when one required instrumentation channel in one or more RB Pressure Parameters becomes inoperable. If one required channel is inoperable, placing it in a tripped Condition leaves the affected actuation train in one-out-of-one condition for actuation and the other actuation channel in a two-out-of-two condition (making the worst case assumption the third channel in each actuation train is not OPERABLE). In this condition, if another RB Pressure ESAS channel were to fail, the ESAS instrumentation could still perform its actuation function. For RB Pressure Parameters, all affected pressure switch trip auxiliary relays must be tripped to comply with this Required Action. This is normally accomplished by tripping the affected pressure switch test switch.

The 72 hour Completion Time is based on engineering judgment and is sufficient time to perform the Required Action.

C.1, C.2, C.3, and C.4

If Required Actions A.1 or B.1 cannot be met within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and, for the RCS Pressure-Low Parameter, to < 1800 psig, for the RCS Pressure-Low Low Parameter, to < 900 psig, and for the RB Pressure High Parameter and High High Parameter, to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

All ESAS Parameter instrumentation listed in Table 3.3.5-1 are subject to CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, CHANNEL CALIBRATION, and response time testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1

Performance of the CHANNEL CHECK every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious.

The 12 hour Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel OPERABILITY during normal operational use of the displays associated with the LCO's required channels.

Acceptance criteria are determined by the plant staff, and are presented in the Surveillance Procedures. The criteria may consider, but is not limited to channel instrument uncertainties, including isolation, indication, and readability.

SR 3.3.5.2

A CHANNEL FUNCTIONAL TEST is performed on each required ESAS channel to ensure the entire channel will perform the intended functions.

The Frequency of 31 days is based on plant operating experience, with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given function in any 31 day interval is unlikely.

A Note has been added to indicate entry into the Required Actions of this Specification may be deferred for up to 8 hours for a channel inoperable for Surveillance testing provided the remaining two ESAS channels are capable of performing the associated ES Function. This allowance considers the average time required to perform the SR and is based on the inability to perform the Surveillance in the time permitted by the Required Actions or the undesirability of performing those ACTIONS.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.3

CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift to ensure that the instrument channel remains operational between successive tests.

The 24 month Frequency is based on the results of comprehensive instrument uncertainty calculations that accommodate 30 months of drift as approved in Amendment 152 (Ref. 4).

SR 3.3.5.4

SR 3.3.5.4 ensures that the ESAS actuation channel response times are less than or equal to the maximum times assumed in the accident analysis. The response time values are the maximum values assumed in the safety analyses. Individual component response times are not modeled in the analyses. Response time testing acceptance criteria are on a Function basis and are included in Reference 1. The analyses model the overall or total elapsed time from the point at which the parameter exceeds the actuation setpoint value at the sensor to the point at which the end device is actuated. Thus, this SR encompasses the automatic actuation logic components addressed under LCO 3.3.7 and the operation of the ES end devices.

Response time tests are conducted on an 24 month STAGGERED TEST BASIS. This results in response time verification of all instrument channels every 72 months. The Frequency is based on plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation but not channel failure are infrequent occurrences.

REFERENCES

1. FSAR, Chapter 7.
2. FSAR, Chapter 14.
3. FSAR, Chapter 6.
4. Amendment No. 152 to the CR-3 Technical Specifications, dated February 13, 1996.

BASES

ACTIONS

A Note has been added to the ACTIONS indicating separate Condition entry is allowed for each ESAS manual initiation Function.

A.1

With one manual initiation channel of one or more ESAS Functions inoperable, the channel must be restored to OPERABLE status within 72 hours. The Completion Time of 72 hours is based on plant operating experience and administrative controls, which provide alternative means of ESAS Function initiation via individual component controls. The 72 hour Completion Time is also consistent with the allowed outage time for a loss of redundancy condition for the safety systems actuated by ESAS.

B.1 and B.2

If the manual initiation channel cannot be restored to OPERABLE status within 72 hours, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1

SR 3.3.6.1 is a CHANNEL FUNCTIONAL TEST of the ESAS manual initiation. The SR verifies manual initiating circuitry is OPERABLE but does not actuate the end device (i.e., pump, valves, etc.). Proper operation of the Function is primarily monitored by ES logic matrix test lights (located on the ES Actuation relay cabinets). The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance is performed with the reactor at power. The 24 month Frequency is based on the results of comprehensive instrument uncertainty calculations that accommodate 30 months of drift as approved in Amendment 152 (Ref. 1).

(continued)

BASES

REFERENCES

1. Amendment No. 152 to the CR-3 Technical Specifications, dated February 13, 1996.

BASES

ACTIONS (continued)

C.1

Condition, C is the default Condition should Required Action A.1 or B.1 not be met within the associated Completion Time.

Required Action CA ensures that Required Actions for affected diesel generator inoperabilities are initiated. Depending on MODE, the Actions specified in LCO 3.8.1, "AC Sources-Operating," or LCO 3.8.2, are required to be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1

A CHANNEL FUNCTIONAL TEST is performed on each required EDG LOPS channel to ensure the entire channel will perform the intended function. This test ensures functionality of each channel to output relays.

The Frequency of 31 days is considered reasonable based on the reliability of the components and on operating experience.

A Note has been added to allow performance of the SR without taking the ACTIONS for inoperable instrumentation channels although during this time period the relay instrumentation cannot initiate a diesel start. This allowance is based on the assumption that the EDG is maintained inoperable during this functional test and the appropriate actions for the inoperable EDG are entered.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.2

A CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. The setpoints and the response to a loss of voltage and a degraded voltage test shall include a single point verification that the trip occurs within the required delay time, as shown in Reference 2.

The 18 month Frequency is based on operating experience and industry-accepted practice.

A Note has been added indicating the voltage sensing device (bus potential transformer) may be excluded from testing since these transformers are passive, inherently stable devices which cannot be calibrated. In the event of transformer failure, the corresponding degraded voltage or loss of voltage relays would trip on low voltage, actuating the associated channel (i.e., the channels fail in the safe condition). In addition, annunciation of failure of a single transformer or associated circuits would be provided via the channel monitor relay, identifying to the operator a failure within the loss of voltage or degraded voltage channels.

REFERENCES

1. FSAR, Chapter 14.

2. FSAR, Section 8.3.

BASES (continued)

ACTIONS

A.1

With one channel of the source range neutron flux indication inoperable, any action to increase reactor power must be suspended until the channel is restored to OPERABLE status. This Action restricts THERMAL POWER increases in a range of operation where the source range instrumentation are the primary means of neutron power level indication. Furthermore, it ensures that power remains below the point where the intermediate range channels come on-scale until both source range channels are available to support the overlap verification required by SR 3.3.9.3. This ensures a transition from one monitoring instrument to another of different range with the reactivity conditions on both sides of the core known.

B.1, B.2, B.3, and B.4

With both source range neutron flux channels inoperable, action is required to preclude increases in neutron count rate requiring source range monitoring capability. This is accomplished by immediately suspending positive reactivity additions and initiating action to insert all CONTROL RODS, and opening the CONTROL ROD drive trip breakers within 1 hour. Periodic SDM verification (of $\geq$ 1% $\Delta k/k$) is then required to provide a means for detecting any slow reactivity changes that could be caused by mechanisms other than CONTROL ROD withdrawal or positive reactivity insertions. Since the source range instrumentation provides the primary indication of power in this plant operating condition, the verification of SDM must continue every 12 hours until at least one channel of source range instrumentation is returned to OPERABLE status. The 1 hour Completion Time for Required Action B.3 and Required Action B.4 are based upon providing sufficient time to accomplish the actions. The 12 hour Frequency for performing the SDM verification is considered adequate to detect any reactivity changes which do occur before SDM limits are approached.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.9.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. The CHANNEL CHECK is a comparison of the parameter indicated on one channel to the other channel. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. Acceptance criteria are determined by the plant staff and presented in the Surveillance Procedure, based on a combination of the channel instrument uncertainties.

The Frequency, about once every shift, is based on operating experience. When operating in Required Action A.1, CHANNEL CHECK is still required for the OPERABLE source range instrument. However, in this Condition, a redundant source range may not be available for comparison. In this case, CHANNEL CHECK may still be performed via comparison with other on-scale neutron flux level initiation, if available, and verification that the OPERABLE source range channel is energized and indicating a value consistent with current plant status.

SR 3.3.9.2

CHANNEL CALIBRATION is a complete check and readjustment of the channels from the count rate amplifier input to the panel meters. The calibration verifies the channel responds to measured parameters within the necessary range and accuracy and leaves the channel adjusted to account for instrument drift. This ensures that the instrument channel remains operational between successive tests.

There is a preamplifier in the instrumentation loop. However, there are no calibration adjustments possible on the preamplifier. The preamplifier has a fixed gain which is set by means of a physical link held in place by screws and which is therefore not subject to unintentional misadjustment. Proper functioning of the preamplifier is initially verified after it or the detector is replaced and is periodically verified by the routine surveillance CHANNEL CHECK required by SR 3.3.9.1. A malfunction or failure of the preamplifier will be apparent as a change in channel output and will result in preamplifier replacement.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.9.2 (continued)

The SR is modified by a Note excluding neutron detectors from CHANNEL CALIBRATION. It is not necessary to test the detectors because generating a meaningful test signal is difficult. The detectors are of simple construction, and any failures in the detectors will be apparent as change in channel output. The 24 month Frequency is based on the results of comprehensive instrument uncertainty calculations that accommodate 30 months of drift as approved in Amendment 152 (Ref. 1).

SR 3.3.9.3

SR 3.3.9.3 is the verification of one decade of overlap between source and intermediate range neutron flux instrumentation. The SR is required to be performed prior to source range count rate exceeding 10^6 cps if it has not been performed within 7 days prior to reactor startup. Failure to verify one decade of overlap on one or more source range channels requires the plant to be maintained in subcritical condition until the verification can be made. This ensures a continuous source of neutron power indication during the approach to criticality. The verification may be omitted if performed within the previous 7 days. The 7 day portion of the Frequency is based on operating experience, which shows that source range and intermediate range instrument overlap does not change appreciably over this time interval.

REFERENCES

1. Amendment No. 152 to the CR-3 Technical Specifications, dated February 13, 1996.

B 3.3 INSTRUMENTATION

B 3.3.10 Intermediate Range Neutron Flux

BASES

BACKGROUND

The intermediate range neutron flux channels provide the operator with an indication of reactor power at power levels between the source range and power range instrumentation.

The intermediate range instrumentation has two log N channels which monitor neutron power levels by means of electrically identical gamma compensated ion chambers (CIC). The CIC are electrically adjustable with separate adjustable high voltage power supply and an adjustable compensating voltage supply. Each channel provides eight decades of flux level information in terms of the log of ion chamber current from 1E-11 amp to 1E-3 amp. The channels also measure the rate of change of the neutron flux level, which is displayed for the operator in terms of startup rate from -0.5 decades to +5 decades per minute. A startup rate of +3 decades per minute in either channel will initiate a CONTROL ROD withdrawal inhibit.

APPLICABLE SAFETY ANALYSES

Intermediate range neutron flux channels are necessary to monitor core reactivity changes during a reactor startup. As such, they are the primary indication to trigger operator actions in the event of reactivity transients starting from low power conditions. However, the monitors are not assumed as part of any accident analysis sequence.

(continued)

BASES (continued)

LCO

Two intermediate range neutron flux instrumentation channels shall be OPERABLE to provide the operator with redundant neutron flux indication. These enable operators to monitor and control the increase in power and to detect neutron flux transients prior to the power range instrumentation coming on scale. Violation of this LCO would limit the ability to "see" reactivity conditions throughout the core and could prevent the operator from detecting and controlling neutron flux transients that could result in reactor trip during power escalation.

APPLICABILITY

The intermediate range neutron flux channels shall be OPERABLE in MODE 2 and in MODES 3, 4 and 5 when any CONTROL ROD drive (CRD) trip breaker is in the closed position and the CRD Control System (CRDCS) is capable of rod withdrawal.

The intermediate range instrumentation is designed to detect power changes during initial criticality and power escalation when the power range and source range instrumentation cannot provide indication. Since an approach to criticality could exist in all of these MODES, the intermediate range instrumentation must be OPERABLE.

ACTIONS

A.1

With one intermediate range channel inoperable, the plant is exposed to the potential for a single failure to disable all neutron monitoring instrumentation. To avoid this, the inoperable channel must be repaired prior to increasing THERMAL POWER > 5% RTP. This limits power increases in a range where the operators rely on the instrumentation for power level indication.

The Completion Time is based on engineering judgment.

B.1 and B.2

With two intermediate range neutron flux channels inoperable, the operators must place the reactor in the next lowest condition for which the intermediate range

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

instrumentation is not required. This involves immediately suspending operations involving positive reactivity changes and, within 1 hour, placing the reactor in the tripped condition with the CRD trip breakers open. The Completion Times are based on operating experience and allow sufficient time to manually insert the CONTROL RODS prior to opening the CRD breakers.

SURVEILLANCE REQUIREMENTS

SR 3.3.10.1

The CHANNEL CHECK is a comparison of the parameter indicated on one channel to the other channel. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious.

When operating in Required Action A.1, CHANNEL CHECK is still required for the OPERABLE intermediate range instrument. However, in this condition, a redundant intermediate range may not be available for comparison. In this case, CHANNEL CHECK may still be performed via comparison with other on-scale neutron flux level indication, if available, and verification that the OPERABLE intermediate range channel is energized and indicates a value consistent with current plant status.

SR 3.3.10.2

For the intermediate range flux channels, CHANNEL CALIBRATION is a complete check and readjustment of the channels from the logarithmic amplifier input to the panel meters. The calibration verifies the channel responds to a measured parameter within the necessary range and accuracy and leaves the channel adjusted to account for instrument drift. This ensures that the instrument channel remains operational between successive tests.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.10.2 (continued)

The SR is modified by a Note excluding neutron detectors from CHANNEL CALIBRATION. It is not necessary to test the detectors because generating a meaningful test signal is difficult. In addition, the detectors are of simple construction, and any failures in the detectors will be apparent as a change in channel output. The 24 month Frequency is based on the results of comprehensive instrument uncertainty calculations that accommodate 30 months of drift as approved in Amendment 152 (Ref. 1).

SR 3.3.10.3

SR 3.3.10.3 is the verification of one decade of overlap between intermediate and power range neutron flux instrumentation. The SR is required to be performed prior to intermediate range indication exceeding 1E-5 amp if it has not been performed within 7 days prior to reactor startup. Failure to verify one decade of overlap on one or more channels requires the plant to remain in a condition where the intermediate range channels provide adequate indication until the verification can be made. This ensures the power range nuclear instrumentation is functioning properly prior to the transition to this range of indication.

The test may be omitted if performed within the previous 7 days. The 7 day portion of the Frequency is based on operating experience, which shows that intermediate range instrument overlap does not change appreciably over this time interval.

REFERENCES

1. Amendment No. 152 to the CR-3 Technical Specifications, dated February 13, 1996.

B 3.3 INSTRUMENTATION

B 3.3.11 Emergency Feedwater Initiation and Control (EFIC) Instrumentation

BASES

BACKGROUND

The EFIC System instrumentation is designed to provide safety grade means of controlling the secondary system as a heat sink for core decay heat removal. To ensure the secondary system remains a heat sink, EFIC initiates emergency feedwater (EFW) when the primary source of feedwater is lost. The system also isolates functional components following a high energy line break within the secondary system. These actions ensure that a source of cooling water is available to a once through steam generator (OTSG) that has a controlled steam pressure, thereby fixing the heat sink temperature at the saturation temperature of the secondary system. The EFIC Functions that are supported by the instrumentation and the parameters that are needed for each of these Functions are described next.

EFIC instrumentation consists of devices and circuitry to generate the following signals when monitored parameters reach pre-set levels.

a. EFW Initiation;

b. EFW Vector Valve Control;

c. Main Steam Line Isolation; and

d. Main Feedwater (MFW) Isolation.

EFW is initiated to restore a source of cooling water to the secondary system when conditions indicate that the normal source of feedwater is insufficient to continue heat removal. The two indications used for ensuring EFW in this condition are the loss of both MFW pumps and a low level in the OTSG. EFW is also initiated at the same time EFIC performs the MFW isolation function. This is done by initiating EFW when OTSG outlet pressure reaches the low OTSG pressure setpoint for isolation of main steam and MFW, and EFW vector valve control. EFW is initiated when the Reactor Coolant System experiences a total loss of forced

(continued)

BASES

BACKGROUND (continued)

circulation. This initiation, utilizing the RPS signal for reactor coolant pump (RCP) status, ensures EFW is available to automatically raise OTSG levels to natural circulation cooling. Finally, EFIC initiates EFW when an actuation is received on HPI Channel A and B. This ensures EFW is available under the worst-case, small break loss of coolant accident (LOCA) conditions when high OTSG water levels are necessary for primary to secondary heat transfer. If adequate subcooling margin is lost, the operator must manually select the inadequate subcooling margin setpoint since EFIC will not automatically raise levels to this point.

EFIC also isolates main steam and MFW to an OTSG that has lost pressure control. With the loss of pressure control, temperature control is also lost and the heat removal rate becomes excessive. Main steam and MFW are isolated to the affected OTSG when steam pressure reaches a low setpoint, a condition which is well below the normal operating pressure of the secondary system.

EFIC also performs an EFW control function to avoid delivering EFW to a depressurized OTSG when the other OTSG remains pressurized. This feed-only-the-good-generator (FOGG) logic is consistent with the design goal of isolating functional components whose pressure cannot be controlled. FOGG logic precludes delivery of emergency feedwater to a depressurized OTSG, thereby preventing an uncontrolled cooldown as long as the other OTSG remains pressurized. When both OTSGs are depressurized, the EFIC logic provides EFW flow to both OTSGs until a significant pressure difference develops between the two, thereby ensuring that core cooling is maintained.

Each EFW actuation logic train actuates on a one-out-of-two taken twice combination of trip signals from the instrumentation channels. Each EFIC channel can issue an initiate command, but an EFIC actuation will take place only if at least two channels issue initiate commands. The one-out-of-two taken twice logic combinations are transposed between trains so that failure of two channels prevents actuation of, at most, one train of EFW.

More detailed descriptions of the EFIC instrumentation are provided next.

(continued)

BASES

BACKGROUND (continued)

1. EFW Initiation

Figure 7-26 of the FSAR, Chapter 7 (Ref. 4) illustrates one channel of the EFIC EFW Initiation channel. The individual instrumentation channels that input to the EFIC EFW Initiation Function are discussed next. The AMSAC and HPI-based EFW Initiation Functions are not described further in these Bases since they are not addressed by Technical Specifications.

a. Loss of MFW Pumps (Control Oil Pressure)

Loss of both MFW Pumps is one of the parameters monitored by EFIC to automatically initiate EFW. MFW pump status (and thus the indication of Loss of MFW Pumps) is detected by MFW pump turbine control oil pressure. The MFW pump status instrumentation is a part of the nuclear instrument (NI)/Reactor Protection System (RPS). Each RPS channel receives MFW Pump status information from pressure switches (four per pump). If both switches in a single channel trip, the associated RPS channel trips. Each RPS channel acts as the sensor for this EFIC Function by providing both MFW Pumps tripped signal indication to the associated EFIC channel. The trip Function is bypassed when THERMAL POWER ≤ 20% RTP and the RPS is placed in shutdown bypass. The bypass is automatically removed when THERMAL POWER increases above 20% RTP.

Loss of both MFW Pumps was chosen as an EFW automatic initiating parameter because it is a direct and immediate indicator of loss of MFW.

b. OTSG Level-Low

Four dedicated low range level transmitters on each OTSG are monitored to generate the signals used for an OTSG Level-Low EFW actuation. The output from each transmitter provides a signal to each of the four EFIC channels A, B, C, and D.

(continued)

BASES

LCO

OTSG Pressure-Low (continued)

transient conditions not requiring secondary system isolation, and has been shown to be an appropriate indicator of secondary side breaks for ensuring automatic EFW actuation. The OTSG Pressure-Low Function includes a bypass enable and removal function. The bypass removal Allowable Value is chosen to allow sufficient operating margin (time) for the operator to bypass the actuation during plant cooldown prior to reaching the actuation setpoint. The 750 psig setpoint allows at least a 10 minute window to perform the bypass assuming the maximum allowed cooldown rate and instrument error.

OTSG Differential Pressure-High

Four EFIC channels for OTSG differential pressure shall be OPERABLE with an allowable value of ≤ 125 psid. The actual plant setpoint is set lower than 125 psid to account for instrument loop uncertainties and setability. The setpoint ensures that automatic EFW isolation to a depressurized OTSG occurs for the range of sizes of SLBs or feedwater line breaks that require rapid actuation early in the event. The setpoint has also been chosen to avoid spurious isolation of EFW during conditions due to relatively small deviations in OTSG pressures that can be caused by primary system conditions. The OTSG Differential Pressure-High Function is bypassed when the OTSG Pressure-Low Function is bypassed.

RCP Status

Four EFIC channels for RCP status are required to be OPERABLE to ensure that upon the loss of all four RCPs, EFW will be automatically initiated. Additionally, EFW will automatically raise and control level to natural circulation value providing a higher driving head for establishing and maintaining natural circulation conditions when forced RCS flow is lost. No setpoint is specified since the status indication used by EFIC is binary in nature. The RCP Status Function includes a bypass enable and removal function from the RPS. The Allowable Value for the bypass removal is set high enough to avoid spurious actuations during low power operation.

RCP status is monitored by two RCPPMs for each RCP. This safety function is lost if both RCPPMs for a single RCP are inoperable and neither is tripped.

(continued)

BASES

APPLICABILITY

EFIC instrumentation OPERABILITY requirements are applicable during the MODES and specified conditions listed in Table 3.3.11-1. Each Function has its own requirements based on the specific accidents and conditions for which it is designed to provide protection.

The initiation of EFW on the Loss of MFW Pumps is applicable in MODE 1 and in MODES 2 and 3 when not in shutdown bypass. Below these plant conditions, EFW initiation on low OTSG level occurs fast enough to prevent primary system overheating.

EFW Initiation on low OTSG level shall be OPERABLE at all times the OTSG is required for heat removal. These conditions include MODES 1, 2, and 3. To avoid automatic actuation of the EFW pumps during heatup and cooldown, the low OTSG pressure Function can be bypassed at or below a secondary pressure of 750 psig. This secondary-side pressure occurs during MODE 3 operation.

EFW initiation on loss of all RCPs is required to be OPERABLE at ≥ 10% RTP. This power level coincides with the bypass permissive signal provided by RPS.

The MFW, Main Steam Line Isolation, and EFW Vector Valve Control Functions shall be OPERABLE in MODES 1, 2, and 3 with OTSG pressure ≥ 750 psig because OTSG inventory can be high enough to contribute significantly to the peak pressure following a secondary side break. Both the normal feedwater and the EFW must be isolatable on each OTSG to limit overcooling of the primary and mass and energy releases to the RB. Once either OTSG pressure decreases below 750 psig, the Main Steam Line and MFW Isolation Functions can be bypassed to prevent actuation during cooldown. The EFW Vector Valve Control logic will not perform any function when both OTSG pressures are low; thus, the logic is also bypassed at the same time the OTSG pressure low Functions is bypassed. In MODES 4, 5, and 6, primary and secondary side energy levels are reduced and the feedwater flow rate is low or nonexistent. Because of this, EFIC instrumentation is not required to be OPERABLE in these MODES.

(continued)

BASES

ACTIONS (continued)

D.1, D.2.1, D.2.2, E.1, and F.1

If the Required Actions cannot be met within the associated Completion Time, the plant must be placed in a MODE or condition in which the requirement for the particular Function does not apply. This requires the operator to open the CRD trip breakers for Function 1.a, MODE 4 for Function 1.b, reduce power to less than 10% RTP for Function 1.d, and reduce OTSG pressure to less than 750 psig for all other Functions. The allowed Completion Times are reasonable, based on operating experience, to reach the specified conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

A Note indicates that the SRs for each EFIC instrumentation Function are identified in the SRs column of Table 3.3.11-1. All Functions are subject to CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION. The SG-Low Level Function is modeled in transient analysis, and is subject to response time testing. Response time testing is also required for Main Steam Line and MFW Isolation. Individual EFIC subgroup relays must also be tested, one at a time, to verify the individual EFIC components will actuate when required. Some components cannot be tested at power since their actuation might lead to reactor trip or equipment damage. These are specifically identified and must be tested when shut down. The various SRs account for individual functional differences and for test frequencies applicable specifically to the Functions listed in Table 3.3.11-1. The operational bypasses associated with each EFIC instrumentation channel are also subject to these SRs to ensure OPERABILITY of the EFIC instrumentation channel when required.

SR 3.3.11.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.11.1 (continued)

monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious.

Acceptance criteria are determined by plant staff and are presented in the Surveillance Procedure. The criteria are based on a combination of the channel instrument uncertainties.

The Frequency, about once every shift, is based on operating experience that demonstrates channel failure is unlikely. Thus, performance of the CHANNEL CHECK ensures that undetected overt channel failure is limited to time intervals between subsequent performances of the SR.

SR 3.3.11.2

A CHANNEL FUNCTIONAL TEST verifies the function of the required trip, interlock, and alarm functions of the channel. The Frequency of 31 days is based on operating experience and industry accepted practice.

SR 3.3.11.3

CHANNEL CALIBRATION is a complete check of the instrument channel including the sensor. The test verifies the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channels adjusted to account for instrument drift to ensure that the instrument channel remains operational between successive tests. The 24 month Frequency is based on the results of comprehensive instrument uncertainty calculations that accommodate 30 months of drift as approved in Amendment 152 (Ref. 6).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.11.4

This SR verifies individual channel response times are less than or equal to the maximum value assumed in the accident analysis. Individual component response times are not modeled in the analysis. The analysis models the overall or total elapsed time from the point at which the parameter exceeds the actuation setpoint value at the sensor, to the point at which the end device is actuated.

EFIC RESPONSE TIME tests are conducted on an 24 month STAGGERED TEST BASIS. Testing of the final actuation devices, which make up the bulk of the EFIC RESPONSE TIME, is included in the testing of each channel. Therefore, staggered testing results in response time verification of these devices every 24 months. The 24 month test Frequency is based on operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences. EFIC RESPONSE TIMES cannot be determined at power since equipment operation, which would induce undesired plant transients, is required.

The SR is modified by a Note indicating the SR is not required to be performed prior to entry into MODE 2. This is due to the fact that secondary side (Main Steam) supply pressure for the turbine driven pump is not sufficient to perform the test until after entering MODE 3. The SR 3.0.4 type allowance is also applicable to the MFW and Main Steam Line isolation Functions, consistent with the allowances provided for the end devices in their respective Specifications (Specifications 3.7.2 and 3.7.3).

REFERENCES

1. FSAR, Section 14.1

2. 10 CFR 50.49.

3. FSAR, Chapter 7.

4. IEEE-279-1971.

5. B&W Document 51-1123786-01, "FOGG Verification Study", May 4, 1981.

6. Amendment No. 152 to the CR-3 Technical Specifications, dated February 13, 1996.

B 3.3 INSTRUMENTATION

B 3.3.12 Emergency Feedwater Initiation and Control (EFIC) Manual Initiation

BASES

BACKGROUND

The EFIC manual initiation capability provides the operator with the capability to actuate certain EFIC Functions in the absence of an automatic initiation condition. Functions with the capability to be manually actuated include Main Feedwater (MFW) Isolation for Once Through Steam Generator (OTSG) A, MFW Isolation for OTSG B, Main Steam Line Isolation for OTSG A, Main Steam Line Isolation for OTSG B, and Emergency Feedwater (EFW) Actuation.

The EFIC manual initiation circuitry satisfies the manual initiation and single-failure criterion requirements of IEEE-279-1971 (Ref. 1).

Although not part of this LCO, the EFIC Functions listed above can also be remotely manually initiated from the EFIC cabinets.

APPLICABLE SAFETY ANALYSES

EFIC Functions credited in the safety analysis are automatic. However, EFIC manual initiation Functions are required by design as backups to the automatic trip Functions. This allows the operator to actuate EFW, Main Steam Line Isolation, or MFW Isolation whenever conditions dictate and one has not already automatically occurred. As such, they are backup Functions to those performed automatically by EFIC.

LCO

Two manual initiation switches per actuation channel (A and B) of each Function (OTSG A and B MFW Isolation, OTSG A and B Main Steam Line Isolation, and EFW Actuation) are required to be OPERABLE whenever the OTSGs are relied on to remove heat from the primary. Each Function (MFW Isolation, Main Steam Line Isolation, and EFW Initiation) has two actuation or "trip" channels, channels A and B. Within each channel A actuation logic there are two manual trip switches. When one manual switch is depressed, a half trip

(continued)

B 3.3 INSTRUMENTATION

B 3.3.16 Control Room Isolation-High Radiation

BASES

BACKGROUND

The principal function of the Control Room Isolation-High Radiation is to provide an enclosed environment from which the plant can be operated following an uncontrolled release of radioactivity. The high radiation isolation function provides assurance that an isolation signal will be generated when conditions dictate. The radiation monitor is located in the control complex return duct. The control room isolation signal is provided by a single channel containing an iodine monitor with a scintillation detector and a gaseous monitor with a Geiger-Mueller detector. The iodine channel includes a particulate prefilter with a charcoal cartridge. If a radioactivity concentration above normal background level is detected on the iodine channel or if power is lost, the monitor will initiate a shutdown of the normal duty supply fans and normal duty return fans and will place the ventilation dampers in their recirculation mode.

Although, not included within the scope of Technical Specifications, the Control Complex is also isolated on an Engineered Safeguards Actuation System (ESAS) RB Pressure-High signal as well as elevated toxic gas levels.

APPLICABLE SAFETY ANALYSES

Following a LOCA, the high radiation function is credited with performing the initial Control Complex isolation function and beginning the emergency recirculation mode of operation. This isolation is necessary to limit doses to the Control Room operator to within 10 CFR 50, Appendix A, General Design Criteria (GDC) 19 limits, (Ref. 1). The limiting GDC 19 dose criteria is the 30 Rem limit to the thyroid. The high radiation isolation would also limits dose rates to the Control Room Operator in the event of a Fuel Handling Accident.

The Control Room Isolation-High Radiation satisfies Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

One channel of Control Room Isolation-High Radiation is required to be OPERABLE to ensure 10 CFR 50, Appendix A, GDC 19 operator and 10 CFR 100 offsite dose limits are met for design basis transients and accidents. Only the iodine channel is addressed by this LCO. Operability of the instrumentation includes proper operation of the sample pump.

APPLICABILITY

The capability to automatically isolate the Control Room on high radiation shall be OPERABLE whenever an accidental release of radioactivity is postulated. This includes MODES 1, 2, 3, 4, and during movement of irradiated fuel assemblies. If a radioactive release were to occur during any of these conditions, the Control Room would have to remain habitable to ensure reactor shutdown and core cooling is maintained.

ACTIONS

A.1

Condition A applies to a failure of the Control Room Isolation-High Radiation Function in MODE 1, 2, 3, or 4.

With the Control Room Isolation-High Radiation instrumentation inoperable, the Control Room Emergency Ventilation System (CREVS) must be placed in a system configuration that minimizes the impact of the inoperable monitor. To ensure that the ventilation system has been placed in a state equivalent to that which occurs after the high radiation isolation has occurred, an OPERABLE train of the CREVS is placed in the emergency recirculation mode of operation. The 1 hour Completion Time is a sufficient amount of time in which to complete the Required Action.

B.1 and B.2

If the CREVS cannot be placed into the emergency recirculation mode or the monitor restored to OPERABLE status within 1 hour while in MODE 1, 2, 3, or 4, actions must be taken to minimize the plant's vulnerability to an accident that would lead to radiation releases. The plant

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.16.3

This SR requires the performance of a CHANNEL CALIBRATION with a setpoint Allowable Value of less than or equal to two times the background count rate.

CHANNEL CALIBRATION is a complete check of the instrument string including and the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations to ensure that the channel remains OPERABLE between successive tests.

The 18 month Frequency is based on engineering judgment and industry-accepted practice.

REFERENCES

1. 10 CFR 50, GDC 19.

2. NUREG-1366, December 1992.

B 3.3 INSTRUMENTATION

B 3.3.17 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The function of PAM instrumentation is to display plant process variables that provide information for the operator to take the manual actions assumed for Design Basis Accident (DBA) mitigation. In addition, certain PAM instrumentation also provides information to assess the performance and status of selected plant systems following a DBA. These essential instruments, identified in FSAR, Table 7-12, (Ref. 1) address the recommendations of Regulatory Guide 1.97 (Ref. 2) as required by Supplement 1 to NUREG-0737 (Ref. 3).

The instrument channels required to be OPERABLE by this LCO are those parameters identified during the CR-3 specific implementation of Regulatory Guide 1.97 as Type A variables and non-Type A, Category I variables. Type A variables are included in this LCO because they provide the primary information that permits the control room operator to take specific manually controlled actions that are required when no automatic control is provided and that are required for safety systems to accomplish their safety functions for DBAs, (Ref. 2). Primary information is that required for the direct accomplishment of the specified safety function; it does not include those variables associated with contingency actions. Category 1 variables are the key variables deemed risk significant for CR-3.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the information is available to the control room operating staff:

a. Perform the diagnosis specified in the emergency operating procedures. These variables are restricted to pre-planned actions for the primary success path of DBAs (e.g., loss of coolant accident (LOCA));

b. Take the specified, preplanned, manually controlled actions, for which no automatic control is provided, which are required for safety systems to accomplish their safety functions;

c. Determine whether systems important to safety are performing their intended functions;

d. Determine the potential for a gross breach of the barriers to radioactivity release;

e. Determine if a gross breach of a barrier has occurred; and

f. Initiate action necessary to protect the public and estimate the magnitude of any impending threat.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

PAM instrumentation that is determined to display a Regulatory Guide 1.97 Type A variable, satisfies Criterion 3 of the NRC Policy Statement. Category 1, non-Type A, instrumentation does not meet any of the criterion in the NRC Policy Statement. However, it is retained in Technical Specifications because it is considered important to reducing risk to the public.

LCO

LCO 3.3.17 requires redundant channels be OPERABLE to ensure no single failure prevents the operators from being presented with the information necessary to determine the status of the unit and to bring the unit to, and maintain it in, a safe condition following that accident. The provision of two channels also allows for relative comparison of the channels (a CHANNEL CHECK type of qualitative assessment) during the post accident phase to confirm the validity of displayed information.

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

Another exception to the redundant channel requirement pertains to the reactor coolant inventory and pressurizer level variables. Various SSCs have been identified that are not protected from the jet impingement and/or pipe whip effects of certain LOCAs. Among these are several components associated with RG 1.97 Post Accident Monitoring Instruments providing pressurizer level indication, and hot leg and reactor vessel level indication for assessing reactor coolant inventory. The subject instruments would be rendered non-functional as a result of the failure of the target SSCs. Therefore, a consequential failure of these instruments due to a LOCA along with a single failure in the redundant train would not satisfy RG 1.97 Category 1 redundancy requirements. However, the failure of these instruments due to the effects of a LOCA does not violate the LCO requirements for operability on the basis that an instrument need not be declared inoperable during normal operation if the instrument has no accident mitigation function for the specific LOCA causing its failure. Details on the basis for this assessment are provided in the discussion for reactor coolant inventory and pressurizer level (Items 4 and 13, respectively).

(continued)

BASES

The following table identifies the specific instrument tag numbers for PAM instrumentation identified in Table 3.3.17-1.

FUNCTION	CHANNEL A	CHANNEL B
1. Wide Range Neutron Flux	NI-15-NI-1 or NI-15-NIR	NI-14-NI-1
2. RCS Hot Leg Temperature	RC-4A-TI4-1	RC-4B-TIR1
3. RCS Pressure(Wide Range)	RC-158-PI2 or RC-158-PIR	RC-159-PI2
4. Reactor Coolant Inventory	RC-163A-LR1 (Hot leg level) and RC-164A-LR1 (Vessel Head level)	RC-163B-LR1 (Hot leg level) and RC-164B-LR1 (Vessel Head level)
5. Borated Water Storage Tank Level	DH-7-LI or DH-7-LIR1	DH-37-LI
6. High Pressure Injection Flow	A1: MU-23-FI8-1 A2: MU-23-FI10 B1: MU-23-FI9 B2: MU-23-FI7-1	A1: MU-23-FI12 A2: MU-23-FI6-1 B1: MU-23-FI5-1 B2: MU-23-FI11
7. Containment Sump Water Level (Flood Level)	WD-303-LI or WD-303-LR	WD-304-LI or WD-304-LR
8. Containment Pressure (Expected Post-Accident Range)	BS-16-PI	BS-17-PI
9. Containment Pressure (Wide Range)	BS-90-PI or BS-90-PR	BS-91-PI or BS-91-PR
10. Containment Isolation Valve Position	**ES Light Matrix "A"**: AHV-1B/1C; CAV-1/3/4/5/126/429/430/433/434; CFV-11/12/15/16; LRV-70/72; MUV-258 thru -261/567;WDV-3/60/94/406; WSV-3/5/28 thru -31/34/35/42/43	**ES Light Matrix "B"**: AHV-1A/1D; CAV-2/6/7/431/432/435/436; CFV-29/42; LRV-71/73; MUV-18/27/49/253; WDV-4/61/62/405; WSV-4/6/26/27/32/33/38/39/40/41
	ES Light Matrix "AB": CFV-25 thru-28; CIV-34/35/40/41; DWV-160; MSV-130/148; SWV-47 thru 50/79 thru 86/109/110	
11. Containment Area Radiation (High Range)	RM-G29-RI or RM-G29-RIR	RM-G30-RI
12. Containment Hydrogen Concentration	WS-11-CR	WS-10-CR
13. Pressurizer Level	RC-1-LIR-1	RC-1-LIR-3
14. Steam Generator Water Level (Startup Range)	**OTSG A:** SP-25-LI1 or SP-25-LIR **OTSG B:** SP-29-LI1 OR SP-29-LIR	**OTSG A:** SP-26-LI1 **OTSG B:** SP-30-LI1

(continued)

FUNCTION	CHANNEL A	CHANNEL B
15. Steam Generator Water Level (Operating Range)	**OTSG A:** SP-17-LI1 or SP-17-LIR **OTSG B:** SP-21-LI1 or SP-21-LIR	**OTSG A:** SP-18-LI1 **OTSG B:** SP-22-LI1
16. Steam Generator Pressure	**OTSG A:** MS-106-PI1 or MS-106-PIR, **OTSG B:** MS-110-PI1 or MS-110-PIR	**OTSG A:** MS-107-PI1 or MS-107-PIR **OTSG B:** MS-111-PI1 or MS-111-PIR
17. Emergency Feedwater Tank Level	EF-98-LI1	EF-99-LI1
18a. Core Exit Temperature (Thermocouple) Quadrant WX XY YZ ZW	IM-5G-TE/IM-6C-TE IM-9E-TE/IM-13G-TE IM-9H-TE/IM-100-TE IM-3L-TE/IM-60-TE	IM-7F-TE/IM-2G-TE IM-10C-TE/IM-11G-TE IM-10M-TE/IM-13L-TE IM-4N-TE/IM-6L-TE
18b. Core Exit Temperature (Recorder)	RC-171-TR	RC-172-TR
19. Emergency Feedwater Flow	**OTSG A:** EF-25-FI1 **OTSG B:** EF-23-FI1	**OTSG A:** EF-26-FI1 **OTSG B:** EF-24-FI1
20. Low Pressure Injection Flow	DH-1-FI1	DH-1-FI2
21. Degrees of Subcooling	As Displayed on EMCO-38 *Note: Entry into LCO 3.3.17 is required if any of the following Hardware or RECALL Points are Out of Service.* **Hardware** Multiplexers EMCO-18/19 Comm. HUBs EMCO-07/20 Computers EMCO-21/40 Monitor EMCO-38 **RECALL Points** RCS Pressure NR RECL-243 RCS Pressure WR RECL-4 T-Hot RECL-17/239	As Displayed on EMCO-39 *Note: Entry into LCO 3.3.17 is required if any of the following Hardware or RECALL Points are Out of Service.* **Hardware** Multiplexers EMCO-27/28 Comm. HUBs EMCO-08/29 Computers EMCO-30/41 Monitor EMCO-39 **RECALL Points** RCS Pressure NR RECL-40 RCS Pressure WR RECL-5 T-Hot RECL-18/240
22. Emergency Diesel Generator kW Indication	EGDG-1A Wattmeter SSF-AH Main control board indicator	EGDG-1B Wattmeter SSF-AX Main control board indicator
23. LPI Pump Run Status	ESFA-LX3 (Red Light) or ESFA-HU (ES Light Matrix "A")	ESFB-LX3 (Red Light) or ESFB-HU (ES Light Matrix "B")
24. DHV-42 and DHV-43 Open Position	ESFA-KN3 (Red Light)	ESFB-KN3 (Red Light)
25. HPI Pump Run Status	**HPI Pump 1A:** ESFA-MF7 (Red Light) or ESFA-AH (ES Light Matrix "A") **OR** **HPI Pump 1B:** ESFA-MN7 (Red Light) or ESFA-AJ (ES Light Matrix "A")	**HPI Pump 1C:** ESFB-MF7 (Red Light) or ESFB-AH (ES Light Matrix "B") **OR** **HPI Pump 1B:** ESFB-MV7 (Red Light) or ESFB-AJ (ES Light Matrix "B")
26. RCS Pressure (Low Range)	RC-147-PI1	RC-148-PI1

NOTES: For Function 18a, each quadrant requires at least 2 OPERABLE detectors, one from each channel. OPERABILITY of only one detector for any quadrant constitutes entry into Condition A of LCO 3.3.17. Any quadrant with no OPERABLE detector constitutes entry into Condition C if LCO 3.3.17. Separate Condition entry is allowed for each quadrant.

For Function 25, OPERABILITY of indication is required only for the one ES selected HPI pump in each channel.

(continued)

BASES

LCO (continued)

The following list is a discussion of the specified instrument Functions listed in Table 3.3.17-1.

1. Wide Range Neutron Flux

Two wide-range neutron flux monitors are provided for post-accident reactivity monitoring over the entire range of expected conditions. Each monitor provides indication over the range of 10^{-8} to 100% log rated power covering the source, intermediate, and power ranges. Each monitor utilizes a fission chamber neutron detector to provide redundant main control board indication. A single channel provides recorded information in the control room. The control room indication of neutron flux is considered one of the primary indications used by the operator following an accident. Following an event the neutron flux is monitored for reactivity control. The operator ensures that the reactor trips as necessary and that emergency boration is initiated if required. Since the operator relies upon this indication in order to take specified manual action, the variable is included in this LCO. Therefore, the LCO deals specifically with this portion of the string.

2. Reactor Coolant System (RCS) Hot Leg Temperature

Two wide range resistance temperature detectors (RTD's), one per loop, provide indication of reactor coolant system hot leg temperature (T_H) over the range of 120° to 920°F. Each T_H measurement provides an input to a control room indicator. Channel B is also recorded in the control room. Since the operator relies on the control room indication following an accident, the LCO deals specifically with this portion of the string.

T_H is a Type A variable on which the operator bases manual actions required for event mitigation for which no automatic controls are provided.

Following a steam generator tube rupture, the affected steam generator is to be isolated only after T_H falls below the saturation temperature corresponding to the pressure setpoint of the main steam safety valves. For event monitoring once the RCP's are tripped, T_H is used along with the core exit temperatures and RCS cold leg temperature to measure the temperature rise across the core for verification of core cooling.

(continued)

BASES

LCO

3. RCS Pressure (Wide Range)

RCS pressure is measured by pressure transmitters with a span of 0-3000 psig. Redundant monitoring capability is provided by two trains of instrumentation. Control room and remote shutdown panel indications are provided. The control room indications are the primary indications used by the operator during an accident. Therefore, the LCO deals specifically with this portion of the instrument string.

RCS pressure is a Type A variable because the operator uses this indication to adjust parameters such as steam generator (OTSG) level or pressure in order to monitor and maintain a controlled cooldown of the RCS following a steam generator tube rupture or small break LOCA. In addition, HPI flow is throttled based on RCS pressure. Finally, HPI flow is required for some small break LOCAs, where LPI may actuate with system pressure stabilizing above the shutoff head of the LPI pumps. If this condition exists, the operator is instructed to verify HPI flow and then stop the LPI pumps in order to preclude extended operation against a deadhead pressure.

4. Reactor Coolant Inventory

Reactor Vessel Water Level instrumentation is provided for verification and long term surveillance of core cooling. The reactor vessel level monitoring system provides a direct measurement of the collapsed liquid level above the fuel alignment plate. The collapsed level represents the amount of liquid mass that is in the reactor vessel above the core. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory.

The collapsed level is obtained over the same temperature and pressure range as the saturation measurements, thereby encompassing all operating and accident conditions where it must function. Also, it functions during the recovery interval. Therefore, it is designed to survive the high steam temperature that may occur during the preceding core recovery interval.

The level range extends from the top of the vessel down to the top of the fuel alignment plate. The response time is short enough to track the level during small break LOCA events. The resolution is sufficient to show the initial level drop, the key locations near the hot leg elevation, and the lowest

(continued)

BASES

LCO

4. Reactor Coolant Inventory (continued)

levels just above the alignment plate. This provides the operator with adequate indication to track the progression of the accident and to detect the consequences of its mitigating actions or the functionality of automatic equipment.

The following instruments associated with reactor coolant inventory monitoring would be rendered non-functional due to the dynamic effects of a LOCA:

- RC-163A-LT1
- RC-163A-TE1
- RC-164A-TE1

These three instruments are used to provide Channel A hot leg and reactor vessel level indication for assessing coolant inventory. In addition, these instruments are designated as part of the CR-3 reactor coolant inventory tracking system (RCITS) which in turn makes up part of the inadequate core cooling (ICC) detection system. All three of these instruments would be rendered non-functional as a result of the same LOCA event, a circumferential terminal end break of the core flood west line at the reactor vessel nozzle. Taking into account a single failure of the Channel B of the RCITS, the operators would be left with no hot leg or vessel level indication capability following this LOCA. However, the RCITS is not a protection system, but a monitoring system with reliable backup from core exit temperature monitors and subcooling margin monitors. The RCITS is not used for control but is meant to provide trending of the reactor coolant inventory. The primary indicators used to ascertain adequate core cooling are RCS temperature and RCS pressure. These two parameters are used to develop degrees of subcooling which are used in the EOPs to trigger specific operator actions. The other Type A variables for the core cooling safety function are core exit temperature and degrees of subcooling. None of the instruments providing measurement and indication of these variables are affected by this accident. In addition, reactor vessel level indication provided by non-safety related instruments RC-201-LT and RC-202-LT may also be available for trending purposes. Therefore, adequate instrumentation would still be available to the operators to determine the adequacy of core cooling.

(continued)

BASES

LCO (continued)

5. Borated Water Storage Tank (BWST) Level

BWST inventory is monitored by level in instrumentation with a span of 0 to 50 feet. Redundant monitoring capability is provided by three independent level measurements. Two level transmitters provide input to control room indicators, and one of these channels is recorded in the control room. The control room indications are the primary indications used by the operator. Therefore, the LCO deals specifically with this portion of the instrument string.

During a design basis LOCA, the Reactor Building Spray, Low Pressure Injection (LPI) and High Pressure Injection (HPI) Systems are automatically aligned to obtain suction from the BWST. As the BWST inventory is pumped into the RCS and containment, coolant will be lost through the break and will accumulate in the reactor building sump. The operator is required to switch LPI and RB Spray suction to the reactor building emergency sump from the BWST when the BWST level reaches a specified level setpoint. At this same time if the RCS pressure is greater than the LPI pump shutoff head, it will also be necessary to switch the suction of the HPI pumps to the discharge of the LPI pumps to ensure the capability to inject flow to the RCS since the HPI pumps do not have the capability of drawing coolant from the sump. BWST level is a Type A variable because it is the primary indication used by the operator to determine when to initiate the switch-over to sump recirculation. This operator action is necessary to satisfy the long-term core cooling requirements specified in 10 CFR 50.46.

6. HPI Flow (Low Range)

HPI flow instrumentaton is provided for verification and long term monitoring of HPI flow. HPI flow is determined from differential pressure transmitters. Two channels in each of the four injection lines, for a total of eight low range indicators, provides this indication. One transmitter is calibrated to a range of 0-200 gpm. Each differential pressure measurement provides an input to a control room indicator. Since the operator relies on the control room indication following an accident, the LCO deals with this portion of the instrument string.

(continued)

BASES

LCO

6. HPI Flow (Low Range) (continued)

Although 4 high range flow indicators (0-500 gpm) readout on the main control board, they are not used to accomplish any safety functions. The HPI lines will have preset throttle valves, stop check valves, and crosstie lines to: (1) create the desired flow distribution through the HPI lines for LOCA core cooling, (2) ensure adequate cooling flow to the HPI pump mechanical seals, and (3) prevent HPI pump flow from exceeding 600 gpm (maximum HPI pump flow rate assumed in design calculations associated with Emergency Diesel Generator loading, ECCS pump available NPSH, and makeup tank (MUT-1) allowable overpressure versus level.)

7. Containment Sump Water Level (Flood Level)

Containment sump water level (Flood) is monitored by two channels of level indication, both of which are displayed in the control room on edgewise level indicators. Channel A and B sump flood level indication are recorded in the associated 'A' and 'B' EFIC Rooms. Each instrument encompasses a range of 0-10 feet above the sump and provides information to the operator related to gross leakage in the Reactor Building. This leakage may be indication of degradation in the reactor coolant pressure boundary (RCPB) which would require further investigation and action. These instruments are not assumed to provide information required by the operator to take a mitigation action specified in the accident analysis. As such, they are not Type A variables. However, the monitors are deemed risk significant (Category 1) and are included within the LCO based upon this consideration.

(continued)

BASES

LCO (continued)

8,9. Containment Pressure (Expected Post-Accident Range and Wide Range)

The containment pressure variable is monitored by two ranges of pressure indication. Expected post-accident range (-10 to 70 psig) and wide range (0 to 200 psig) pressure indication each provide two channels of pressure indication. Channel A and B wide range containment pressure are recorded in the associated 'A' and 'B' EFIC Rooms. The low range is required in order to ensure instrumentation of the necessary accuracy is available to monitor conditions in the RB during DBAs. The wide range instrument was required by Regulatory Guide 1.97 to be capable of monitoring pressures over the range of atmospheric to three times containment design pressure (approximately 165 psig). Thus, it was intended to monitor the RB in the event of an accident not bounded by the plant safety analysis (i.e., a Severe Accident).

These instruments are not assumed to provide information required by the operator to take a mitigation action specified in the accident analysis. As such, they are not Type A variables. However, the monitors are deemed risk significant (Category 1) and are included within the LCO based upon this consideration.

10. Containment Isolation Valve Position

Containment Isolation Valve (CIV) position indication instrumentation is provided in order for the operator to verify that RB penetrations are isolated, as required, following an accident or transient. In this way, the Containment is verified to be functioning as analyzed and as tested (10 CFR 50, Appendix J). The CIV indication consists of open/closed matrix lights located on the ES Section of the main control board.

CR-3 does not provide position indication for manual CIVs or CIVs utilizing a passive design (check valves). In the case of manual valves, these valve types are acceptable alternatives to automatic valves for the purposes of providing containment isolation and require no position indication since they are administratively maintained in the isolated position. Position indication for check valves is specifically excluded by Table 3 of Regulatory Guide 1.97.

(continued)

BASES

LCO

10. Containment Isolation Valve Position (continued)

The LCO requires two position indications per penetration rather than two indications per valve (for those penetrations provided with indication and the applicable valve configuration). In other words, the LCO requires one position indicator for each of two active CIVs with control room indication. Strictly speaking, this is an exception from Category 1 redundancy requirements. However, this is considered acceptable since redundancy is provided on a per-penetration basis. For penetrations having only one CIV having control room indication, only that one indication is required by this LCO.

A Note has been added to indicate that position indication is not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. This allowance is consistent with the previous discussion on why position indication was excluded for manual valves.

These instruments are not assumed to provide information required by the operator to take a mitigation action specified in the safety analysis. As such, they are not Type A variables. However, the monitors are deemed risk significant (Category 1) and are included within the LCO based upon this consideration.

11. Containment Area Radiation (High Range)

Containment Area Radiation (High Range) instrumentation is provided to monitor the potential for significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans.

Two channels of indication, each having a range of 1 to 1E8 Rad/hr. are provided in the control room with one channel recorded. These instruments are not assumed to provide information required by the operator to take a mitigation action specified in the accident analysis. As such, they are not Type A variables. However, the monitors are deemed risk significant (Category 1) and are included within the LCO based upon this consideration.

(continued)

BASES

LCO

12. Containment Hydrogen Concentration

Containment Hydrogen Concentration instrumentation is provided to detect high hydrogen concentration conditions that represent a potential for containment breach. The operator is expected to initiate hydrogen control actions based upon indication provided by this instrument. These include hydrogen purge or recombiner initiation when hydrogen concentration reaches or exceeds the 4.1 volume percent flammability limit for hydrogen. This variable is also important in verifying the adequacy of mitigating actions since hydrogen concentration is not expected to approach flammability limits for any Design Basis Accident.

Two channels of indication, each covering a range of 0 to 10% hydrogen concentration are provided in the EFIC Room. Both channels are recorded in the EFIC room as well. These channels are not normally energized and thus are not subject to the CHANNEL CHECK requirement of SR 3.3.17.1.

These instruments are not assumed to provide information required by the operator to take a mitigation action specified in the accident analysis. As such, they are not Type A variables. The basis for this statement is that in order to generate bulk hydrogen concentrations which meet or exceed the flammability limit, core damage in excess of that allowed by 10 CFR 50.46 must occur. However, this is precluded by all other accident analysis. Thus, although the plant is designed to be capable of performing this function, it is not a requirement of the accident analysis. Be that as it may, the monitors are deemed risk significant (Category 1) and are included within the LCO based upon this consideration.

13. Pressurizer Level

Pressurizer level is indicated to provide information on proper operation of the pressurizer for a variety of anticipated transients. These include decreasing feedwater temperature, excessive main feedwater flow, decreasing steam flow, small steam leaks, loss-of-offsite power (and subsequent natural circulation ensured by pressurizer heater operation), loss of condenser vacuum, as well as several others. For these events, pressurizer level is expected to remain on-scale for the installed indication.

(continued)

BASES

LCO

13. Pressurizer Level (continued)

For severe transients or accidents such as a steam line break, steam generator tube rupture, and many small break LOCAs, the pressurizer will void. For the case of a loss of main feedwater, the pressurizer could potentially be made water-solid. This is undesirable in that RCS pressure control is degraded and the potential for passing liquid through the pressurizer safety valves is increased. Studies have shown the safeties have a higher potential to fail to re-seat (creating an unisolable LOCA) if this condition were to occur.

Two channels of pressurizer level, each covering a range of 0 to 320 inches, are indicated and recorded in the control room. These instruments are not assumed to provide information required by the operator to take a mitigation action specified in the safety analysis. As such, they are not Type A variables. However, the monitors are deemed risk significant (Category 1) and are included within the LCO based upon this consideration.

The following instrument associated with primary coolant system operation monitoring would be rendered non-functional due to the dynamic effects of a LOCA:

- RC-1-LT3

RC-1-LT3 is a transmitter used in providing pressurizer level indication (RC-1-LIR-3) in one of two RG 1.97 compliant instrument strings. There is also a third non-safety related pressurizer level instrument string. Pressurizer level is classified as a Type D variable that is used to indicate proper operation of the pressurizer and one of the parameters demonstrating operation of the reactor coolant system. The tubing associated with this instrument would be a jet impingement target of a pressurizer surge line rupture. Failure of the tubing pressure boundary would result in the indication failing to the low position, i.e., show the pressurizer level off-scale low. Assuming a single failure of the redundant safety-related train of pressurizer level indication (RC-1-LIR-1) would result in neither train indicating pressurizer level. However, the redundant train

(continued)

BASES

LCO

13. Pressurizer Level (continued)

would indicate no pressurizer level regardless of any consideration of a single failure for this specific accident. As noted above, the pressurizer will void for many small break LOCAs. Specifically, since the LOCA of concern is the pressurizer surge line, the pressurizer will void causing the level indication to go off-scale low even if both trains were to remain operable. This fact was highlighted in CR-3's request for an exception to RG 1.97 requirements regarding the scale of the level indicating instrumentation. The SER for this exception stated that the range was acceptable because, "For severe transients (accidents), the pressurizer will either void or go solid. This would cause the pressurizer level indication to go off-scale low or high depending on the accident, regardless of the span of the range. In these cases of off-scale pressurizer instrumentation, action to be taken must be determined by subcooling margin, RCS pressure, PORV status, and pressurizer safety valve status." These indications would all still be available after this LOCA event. Therefore, loss of pressurizer level indication would not inhibit the operators in their ability to mitigate the accident and bring the plant to a safe shutdown condition.

14,15. Steam Generator Water Level (Start-up Range and Operating Range

The CR-3 Type A/Category 1 indication of steam generator level is the startup range and operating range EFIC level instrumentation. The combined instrument ranges cover a span of 6 to 394 inches above the lower tubesheet. The measured low range differential pressure is displayed in inches of water. The low range indicates a range of 0 to 150 inches, where 0 inches indicates an actual level of 6 inches above the lower tubesheet. The high range steam generator level instrumentation indicates a span of 0 to 100%, where 0% corresponds to a 102 inch actual level above the lower tubesheet. Redundant monitoring capability is provided by two channels of each range of instrumentation per OTSG.

(continued)

BASES

LCO

14,15. Steam Generator Water Level (Start-up Range and Operating Range (continued)

The level signals are displayed on control room indicators. The steam generator level signals are calculated from differential pressure signals which are pressure compensated by a module in the EFIC System cabinets. Compensation is based on the densities of the water and steam assuming the OTSGs are normally operating at saturation. Each operating range level transmitter also inputs to a recorder in the control room. Since operator action is based on the control room indication, the LCO deals specifically with this portion of the instrument string.

16. Steam Generator Pressure

Steam generator pressure is measured on each main steam line between the respective main steam safety valves and the main steam isolation valve. Redundant monitoring capability is provided by two pressure transmitters per OTSG. Each pressure transmitter provides an input signal to pressure indicators and a recorder in the control room. The control room indication of OTSG pressure is one of the primary indications used by the operator during an accident. Therefore, the LCO deals specifically with the control room indication portion of the OTSG pressure instrument string. The range of the indication is 0 to 1200 psig.

OTSG pressure decreases rapidly during a design basis steam line break accident. This rapid decrease in pressure is a positive indication of a breach in the secondary system pressure boundary. In order to minimize the primary system cooldown caused by the decreasing secondary system pressure, feedwater flow to the affected OTSG must be terminated. OTSG pressure is considered a Type A variable because it is the primary indication used by the operator to identify and isolate the affected OTSG. In addition, OTSG pressure is a key parameter used by the operator to evaluate primary-to-secondary heat transfer. For example, the operator may use this indication to control the primary system cooldown following a steam generator tube rupture or a small break loss of coolant accident (LOCA).

(continued)

BASES

LCO (continued)

17. Emergency Feedwater Tank Level

The dedicated emergency feedwater (EFW) tank provides the assured, safety grade water supply for the Emergency Feedwater System. The EFW tank inventory is monitored and displayed by 0 to 38 feet control room level indications. The control room indicators and alarms are considered the primary indication used by the operator. Therefore, the LCO deals specifically with this portion of the instrument string.

The design basis accidents which require emergency feedwater are those in which the main feedwater supply and/or the electrical supply to the vital feedwater auxiliaries has been lost, e.g., a feedwater line break or a loss of offsite power. In the event of such a loss of feedwater, the EFW tank is the initial source of water for the EFW System. As the EFW tank is depleted, manual operator action is necessary to replenish the EFW tank or to realign the suction to the EFW pumps. Since tank level is required by the operator for manual actions following an event, it has been included in this LCO.

18a. Core Exit Temperature (Thermocouple)

The core exit thermocouples (CETs) provide an indication of the reactor coolant temperature as it exits the active region of the core. The CETs provide input to accident monitoring instrumentation over a range of 0 to 2500°F, and include 16 separate temperature measurements from 16 CETs, four from each quadrant. These 16 core exit temperature measurements are continuously recorded in the control room on two separate recorders as described in Function 18b, and provide input to the Safety Parameter Display System (SPDS) for determining subcooling margin as described in Function 21. Since the distribution of OPERABLE CETs is important for assuring a representative indication of temperatures across the core, this LCO deals specifically with this portion of the instrument string.

The CETs are considered the primary indication of the reactor coolant temperature. The CETs are included in this LCO because the operator uses the indication from the CETs to monitor the cooldown of the RCS following a steam generator tube rupture or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting OTSG level or pressure, would be prompted by this indication.

(continued)

BASES

LCO (continued)

18b. Core Exit Temperature (Recorder)

The core exit temperature recorders provide an indication of the reactor coolant temperature as it exits the active region of the core over a range of 0 to 2500°F. Input to each recorder is from eight CETs, two from each core quadrant, to provide a representative distribution of temperatures across the core. Since the control room display is the primary indication used by the operator, this LCO deals specifically with this portion of the instrument string.

Core exit temperature is considered the primary indication of the reactor coolant temperature, and is included in this LCO because the operator uses this indication to monitor the cooldown of the RCS following a steam generator tube rupture or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting OTSG level or pressure, would be prompted by this indication.

19. Emergency Feedwater Flow

EFW Flow instrumentation is provided to monitor operation of decay heat removal via the OTSGs. The EFW injection flow to each OTSG (2 channels per OTSG, one associated with each EFW injection line) is determined from a differential pressure measurement calibrated to a span of 0 gpm to 1000 gpm. Each differential pressure transmitter provides an input to a control room indicator and the plant computer.

EFW Flow is used by the operator to determine the need to throttle flow during accident or transient conditions to prevent excessive RCS cooldown rates when low decay heat levels are present. EFW Flow is also used by the operator to verify that the EFW System is delivering the correct flow to each OTSG. However, the primary indication of this function is provided by OTSG level.

These instruments are not assumed to provide information required by the operator to take a mitigation action specified in the safety analysis. As such, they are not Type A variables. However, the monitors are deemed risk significant (Category 1) and are included within the LCO based upon this consideration.

(continued)

BASES

LCO (continued)

20. Low Pressure Injection Flow

Low pressure injection flow instrumentation is provided to monitor flow to the RCS following a large break LOCA. It is also used to monitor LPI flow during piggy back operation following a small break LOCA. The low pressure injection flow to the reactor (2 channels, one associated with each LPI injection line) is determined from a differential pressure measurement calibrated to a span of 0 gpm to 5000 gpm.

The LPI flow indication is used by the operator to throttle the flow to ≤ 2000 gpm prior to switching the pump suction from the BWST to the RB sump. This assures adequate net positive suction head (NPSH) is maintained to the pump. The indication is also used to verify LPI flow to the reactor as a prerequisite to termination of HPI flow.

Since low pressure injection flow is a Type A variable on which the operator bases manual actions required for event mitigation for which no automatic controls are provided, it has been included in this LCO.

21. Degrees of Subcooling

Two channels of subcooling margin with inputs from RCS hot leg temperature (T_H), core exit temperature, and RCS pressure are provided by the Safety Parameter Display System (SPDS). Multiple core exit temperatures are auctioneered with only the highest temperature being input to the monitor. The T_H inputs to the SPDS subcooling margin monitors operate over a range of 120 to 920°F. The core exit temperature inputs operate over a range of 0 to 2500°F. RCS pressure inputs operate over a wide range of 200 to 2500 psig and low range of 0 to 600 psig.

(continued)

BASES

LCO

21. Degrees of Subcooling (continued)

The subcooling margin monitors are used to verify the existence of, or to take actions to ensure the restoration of subcooling margin. Specifically, a loss of adequate subcooling margin during a LOCA requires the operator to trip the reactor coolant pumps (RCP's), to ensure high or low pressure injection, and raise the steam generator levels to the inadequate subcooling margin level. Since degrees of subcooling is a Type A variable on which the operator bases manual actions required for event mitigation for which no automatic controls are provided, it has been included in this LCO.

22. Emergency Diesel Generator, kW Indication

The Emergency Diesel Generator (EDG) provides standby (emergency) electrical power in the case of Loss of Offsite Power (LOOP). EDG kW indication is provided in the control room to monitor the operational status of the EDG.

EDG Power (kW) output indication is a type A variable because EDG kW indication provides the control room operator EDG load management capabilities. EDG load management enables the operator to base manual actions of load start and stop for event mitigation.

(continued)

BASES

LCO (continued)

23. LPI Pump Run Status

LPI Pump Run Status is used by the operator during the ECCS Pump Suction Transfer to initiate the opening of DHV-11 and DHV-12, the "Piggyback" valves.

LPI Pump Run Status is a Type A variable because the opening of these valves to establish a suction source is a planned manual action and is necessary to maintain HPI in LOCAs where the RCS pressure has not decreased to the point that LPI will provide injection of coolant into the Reactor Coolant System and when single failures occur which result in only one train of LPI being available.

24. DHV-42 and DHV-43 Open Position

DHV-42 and DHV-43 Open Position, the suction valves from the RB sump to the LPI pumps, are used by the operator during the ECCS Pump Suction Transfer to initiate the closing of DHV-34 and DHV-35, the suction valves from the BWST to the LPI pumps.

DHV-42 and DHV-43 Open Position are Type A variables because the closing of DHV-34 and DHV-35 to manually isolate the BWST from the LPI and BS suction is necessary to prevent vortexing and consequential damage to the LPI and BS pumps, which are required for maintaining core and containment cooling.

25. HPI Pump Run Status

HPI Pump Run Status is used by the operator in determining the total HPI flow per pump. If the total flow decreases below the minimum pump flow limits, then a manual action is taken to open the recirculation valves in order to avoid low flow operation which could damage the pump and render it inoperable while it is being used to mitigate a design basis accident.

HPI Pump Run Status is a Type A variable because there are some SBLOCAs that would result in HPI flows of this small a magnitude. Since these actions are necessary to protect equipment that is necessary to mitigate the accident, these are Type A variables.

(continued)

BASES

LCO (continued)

26. RCS Pressure (Low Range)

RCS pressure is measured by pressure transmitters with a span of 0-600 psig. Redundant monitoring capability is provided by two trains of instrumentation. The control room indications are the primary indications used by the operator during an accident. Therefore, the LCO deals specifically with this portion of the instrument string.

RCS Pressure (Low Range) is classified as a Type B Category 1 variable because none of the actions taken by the operator based on RCS pressure variables qualifies it as a Type A variable. It is included in Table 3.3.17-1 as it is a Category 1 variable and relied on by the operators to maintain RCS pressure for several contingency actions included in the EOPs. Those actions are: 1) determination that an ES actuation of the LPI pumps should have occurred, 2) selecting Low Temperature Overpressure Protection (LTOP), 3) opening of drop lines to establish Decay Heat Removal, 4) ensure adequate RCP NPSH at low RCS pressure, and 5) ensure NDT limits have not been exceeded.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.17.1 (continued)

A note to the Surveillance excludes the performance of a CHANNEL CHECK on Function 4. FPC requested, and was granted, exception from performing a CHANNEL CHECK on this instrumentation as part of Amendment 124, dated October 17, 1989. The basis for not performing this SR is based on the design of the system. The system utilizes differential pressure (dp) measurements across vertical elevations of the hot leg and the reactor vessel when the RCPs are tripped. Performance of the SR with the RCPs in operation provides no meaningful information, such that a CHANNEL CHECK of this Function is not required.

SR 3.3.17.2

CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor, to verify the channel responds to the measured parameter(s) within the necessary range and accuracy.

For the Containment Area Radiation instrumentation, a CHANNEL CALIBRATION consists of an electronic calibration of the channel, not including the detector, for range decades above 10 R/hr. The calibration also provides a one point check of the detector below 10 R/hr using a gamma test source (Reference NUREG 0737, Table II.F.1-3).

The 24 month Frequency is based on the results of comprehensive instrument uncertainty calculations that accommodate 30 months of drift as approved in Amendment 152 (Ref. 5). The Frequency for the hydrogen monitors is 18 months based on operating experience and was originally selected to be consistent with the typical industry fuel cycle.

A Note clarifies that the neutron detectors are not required to be tested as part of the CHANNEL CALIBRATION. Adjustment of the detectors is unnecessary because they are passive devices and operating experience has shown them to exhibit minimal drift. Furthermore, there is no adjustment that can be made to the detectors.

A Note to the Surveillance excludes the performance of a CHANNEL CALIBRATION on Functions 23 and 25. FPC requested, and was granted, exception from performing a CHANNEL CALIBRATION on this instrumentation as part of Amendment 177, dated June 3, 1999. Since no adjustment of these on-off indications is possible, performance of the SR provides no meaningful information such that a CHANNEL CALIBRATION of this Function is not required. Instead, these indications are subjected to a CHANNEL FUNCTIONAL TEST as described in SR 3.3.17.3.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.17.3

CHANNEL FUNCTIONAL TEST is, for switch contacts, the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify OPERABILITY, including required alarm and trip functions.

For the LPI Pump Run Status, and the HPI Pump Run Status, the CHANNEL FUNCTIONAL TEST verifies the red indicating lights on the main control board and the ES Light Matrix indicators during testing of the pumps already required by other surveillance requirements.

The 24 month frequency is based on providing consistency between this surveillance testing and the other surveillance requirements for verifying operability of these specific pumps.

REFERENCES

1. FSAR, Table 7-12.

2. Regulatory Guide 1.97, Revision 3.

3. NUREG-0737, 1979.

4. 32-1177256-00, "Technical Basis for Reactor Vessel Level Indication System (RVLIS) Action Statement," April 10, 1990.

5. Amendment No. 152 to the CR-3 Technical Specifications, dated February 13, 1996.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.18.2

CHANNEL CALIBRATION is a complete check of the instrument loop and sensor. The SR verifies that the channel responds to the measured parameters within the necessary range and accuracy.

A Note clarifies that Function 1.a., "Reactor Trip Breaker (RTB) Position" is not required to have a CHANNEL CALIBRATION. This indication is mechanical in nature, and thus, not subject to a calibration.

The 24 month Frequency is based on the results of comprehensive instrument uncertainty calculations that accommodate 30 months of drift as approved in Amendment 152 (Ref. 3).

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.

2. 10 CFR 50, Appendix R, Section L.

3. Amendment No. 152 to the CR-3 Technical Specifications, dated February 13, 1996.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within the limits assumed in the safety analyses. The analyses of normal operating conditions, including anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on DNB related parameters ensure that these parameters will not be less conservative than were assumed in the analyses and thereby provide assurance that the minimum departure from nucleate boiling ratio (DNBR) will meet the required criteria for each of the transients analyzed.

The RCS pressure limit is consistent with operation within the nominal operating envelope and is above the value used as the initial pressure in the analyses. A pressure greater than the minimum specified will produce a higher DNBR. A pressure lower than the minimum specified will cause the plant to approach the DNB limit.

The RCS coolant hot leg temperature limit is consistent with full power operation within the nominal operating envelope and is lower than the initial hot leg temperature in the analyses. A hot leg temperature lower than that specified will produce a higher DNBR. A temperature higher than that specified will cause the plant to approach the DNB limit.

The RCS flow rate is a function of the number of RCPs in operation and is not expected to vary during operation. The minimum RCS flow rate limit corresponds to that assumed for the DNBR analyses. A higher RCS flow rate will produce a higher DNBR. A lower RCS flow will cause the plant to approach the DNB limit.

APPLICABLE SAFETY ANALYSES

The requirements of LCO 3.4.1 represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

that transients initiated from the limits of this LCO will meet the event-specific DNBR acceptance criterion. This is the acceptance limit for the RCS DNBR parameters. The transients analyzed for include loss of coolant flow events and dropped or stuck control rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.2.1, "Regulating Rod Insertion Limits," LCO 3.2.2, "APSR Insertion Limits," LCO 3.2.3, "AXIAL POWER IMBALANCE OPERATING LIMITS," and LCO 3.2.4, "QUADRANT POWER TILT."

The core outlet pressure assumed in the safety analyses is 2135 psia. The minimum pressure specified in LCO 3.4.1 is the limit value in the reactor coolant loop as measured at the hot leg pressure tap.

The safety analyses are performed with an assumed RCS coolant average temperature of 581°F (579°F plus 2°F allowance for calculational uncertainty). The corresponding hot leg temperature of 604.6°F is calculated by assuming an RCS core outlet pressure of 2135 psia and an RCS flow rate of 374,880 gpm. The maximum temperature specified is the limit value at the hot leg resistance temperature detector.

The safety analyses are performed with an assumed RCS flow rate of $\leq$ 374,880 gpm. The flow rate specified in SR 3.4.1.3 is the corresponding mass flow rate for full-power conditions.

Analyses have been performed to establish the pressure, temperature, and flow rate requirements for three pump operation as well. The flow limits for three pump operation are approximately 25% lower than the four pump limits. To meet the DNBR criterion, a corresponding maximum power limit of less than the top of the "doghouse" (Power-Imbalance-Flow trip setpoint contained in the COLR) is required in combination with the 3 pump limits (see Bases for LCO 3.3.1, "RPS Instrumentation").

RCS DNB limits satisfy Criterion 2 of the NRC Policy Statement.

LCO

Limits on RCS loop (hot leg) pressure, RCS hot leg temperature, and RCS total flow rate ensure that the core

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB. Reference 8 establishes the methodology for determining the P/T limits. Since the P/T limits are not derived from any DBA analysis, there are no accident analysis acceptance limits related to the P/T limits. Rather, the P/T limits are acceptance limits themselves since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of the NRC Policy Statement.

LCO

The two elements of this LCO are:

a. The limit curves for heatup, cooldown, and ISLH testing; and LTOP, and

b. Limits on the rate of change of temperature.

The LCO limits apply to all components of the RCS, except the pressurizer. The limits define allowable P/T operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ISLH P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

Violating the LCO limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCPB components. The consequences depend on several factors, as follows:

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature;

(continued)

BASES

LCO (continued)

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existences, sizes, and orientations of flaws in the vessel material.

APPLICABILITY

The RCS P/T limits Specification provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 1). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, the limits are applicable at all times. MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent. The limits do not apply to the pressurizer.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; LCO 3.4.2, "RCS Minimum Temperature for Criticality"; and Safety Limit (SL) 2.1, "SLs," also provide operational restrictions on the combination of RCS pressure and temperature as well as maximum pressure.

ACTIONS

The Actions of this LCO consider the premise that a violation of the limits occurred during normal plant maneuvering. Severe violations caused by abnormal transients, at times accompanied by equipment failures, may also require additional actions from emergency operating procedures.

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

allowable limits. Restoration alone, per Required Action C.1, is insufficient, in and of itself, to justified continued operation because higher than analyzed stresses may have occurred and may have affected RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the limits specified in the PTLR is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. These planned evolutions include heatup, cooldown and ISLH testing. As such, this SR is modified by a Note that only requires this SR to be performed during system heatup, cooldown, and ISLH testing. The definition of what constitutes a heat-up or cooldown is defined in the applicable plant procedure.

The 30 minute Frequency is considered reasonable in view of the control room indication available to monitor RCS status. In addition, since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction for minor deviations within a reasonable time.

REFERENCES

1. 10 CFR 50, Appendix G.

2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.

3. NUREG-0800, Section 5.3.1, Rev. 1, July 1981.

4. Regulatory Guide 1.99, Revision 2, May 1988.

5. ASTM E 185-82, July 1982.

(continued)

BASES

REFERENCES (continued)

6. 10 CFR 50, Appendix H.

7. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

8. BAW-10046A, Rev. 2, April 1986.

9. ASME Code Case N-514, "Low Temperature Overpressure Protection, Section XI, Division 1."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops–MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer of this heat to the steam generators (OTSGs) or decay heat removal (DHR) heat exchangers. While the principal means for decay heat removal is via the DHR System, the OTSGs are an acceptable backup means. Although the OTSGs cannot remove heat unless steaming occurs (which is not possible in MODE 5), they are available as a temporary heat sink and can be used by allowing the RCS to heat up into the temperature region of MODE 4 where steaming can be effective for heat removal. The secondary function of the reactor coolant is to act as a transfer medium for the soluble neutron poison, boric acid.

In MODE 5, DHR loops are the preferred means for heat removal. The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one DHR loop for decay heat removal and coolant circulation. The flow provided by one DHR loop is adequate for these purposes. The other purpose of this LCO is to require that a second path be available to provide redundant heat removal capability.

The LCO provides for either OTSG heat removal or DHR System heat removal as an acceptable backup to the loop in operation. In MODE 5, reactor coolant pump (RCP) operation is restricted because of net positive suction head (NPSH) limitations, and the OTSG will not be able to provide steam for the turbine driven feedwater pumps. Therefore, in order to ensure that a OTSG can be used as a heat sink, a non-steam driven feed source is needed. A main feedwater booster pump, the auxiliary feedwater pump (FWP-7), the diesel driven emergency feedwater pump, or motor driven emergency feedwater pump can be used. Additionally, steam-driven feedwater pumps, with auxiliary steam from Units 1 and 2, are also viable feed sources. It is preferable that the high entry point in the generator (EFW nozzles) is accessible from the feedwater pumps (< 150°F temperature required) so that natural circulation can be stimulated. If this flow path is not available, the normal FW entry point (MFW nozzles) can be used provided the OTSG level is ≥ 95% on the operate scale (spillover into the MS lines must be avoided). In either case, the capability to steam the OTSG, either through its atmospheric dump valve (ADV) or turbine bypass valves (TBVs), if the condenser is available, must be available in order to provide a heat sink path. The OTSGs are primarily a backup to the DHR pumps, which are

(continued)

BASES

BACKGROUND (continued)

used for forced flow. When relying upon the OTSGs to be a backup heat removal path, the option to increase RCS pressure and temperature for heat removal in MODE 4 is provided.

APPLICABLE SAFETY ANALYSES

No safety analyses are performed with initial conditions in MODE 5. The flow provided by one decay heat removal pump is adequate to prevent boron stratification in the vessel core region during a reduction of boron concentration.

RCS loops–MODE 5 (loops filled) were identified in the NRC Policy Statement as important contributors to risk reduction.

LCO

The purpose of this LCO is to require that at least one of the DHR loops be OPERABLE and in operation. The LCO also requires an additional DHR loop or OTSG to be OPERABLE. One DHR loop provides sufficient forced circulation to perform heat removal and boron mixing functions under these conditions. The second DHR loop is maintained as a backup to the operating DHR loop to provide redundant decay heat removal capability. If the standby DHR loop is not OPERABLE, a sufficient alternate method of providing redundant heat removal paths is to provide an OPERABLE OTSG. To be considered OPERABLE, the capability to feed the generator through the high (EFW, < 150°F temperature required) nozzles or through the low (MFW) nozzles (providing the secondary side water level is maintained ≥ 95% on the operate scale) must exist AND the capability to steam the generator through the ADVs or TBVs must exist (Ref. 1). Should the operating DHR loop fail, the OTSGs can be used to remove the decay heat.

In MODE 5, it is sometimes necessary to stop all RCP or DHR pump forced circulation. Examples of this include swapping from one DHR train to the other, performing surveillance or startup testing, performing the transition to and from the DHR System, or to avoid operation below the RCP minimum NPSH limit.

Note 1 permits the DHR pumps to be stopped for up to 1 hour per 8 hour period for any reason. Sound operating principles dictate that the circumstances for stopping both DHR trains should be limited to situations where:
(a) Pressure and temperature increases can be maintained

(continued)

BASES

LCO (continued)

well within the allowable pressure and subcooling limits; or (b) Alternate heat removal paths through an OTSG is in operation. The Note prohibits boron dilution when DHR forced flow is stopped because an even concentration distribution cannot be ensured. Core outlet temperature is to be maintained so as to assure subcooling throughout the RCS so that no vapor bubble would form and possibly cause a natural circulation flow obstruction. In this MODE, the OTSG is a backup for decay heat removal and, the RCS must be maintained subcooled to ensure its availability.

Note 2 allows one DHR loop to be inoperable for a period of up to 2 hours provided that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on a DHR loop during the optimum plant conditions.

The time periods for each of these allowances is acceptable because natural circulation is adequate for heat removal, the reactor coolant temperature can be maintained subcooled, and boron stratification affecting reactivity control is not expected.

Note 3 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of DHR loops from operation provided at least one RCP is in operation. This Note provides for the transition to MODE 4 recognizing an RCS loop is permitted to be in operation and replaces the heat removal function provided by the DHR loops.

An OPERABLE DHR loop is composed of an OPERABLE DHR pump, OPERABLE DHR heat exchanger, and associated flowpath. DHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. An OTSG can perform as a heat sink when it has an available feed source (≥ 95% OTSG level if through MFW nozzles or < 150°F if through EFW nozzles), and an available path for steam flow.

(continued)

BASES

APPLICABILITY

In MODE 5 with loops filled, forced circulation is provided by this LCO to remove decay heat from the core and to provide proper boron mixing. One loop of DHR provides sufficient circulation for these purposes. With the loops filled, the second DHR loop or an OTSG is a viable heat removal option.

Forced circulation is required in all MODES and is addressed by the following Specifications:

LCO 3.4.4, "RCS Loops-MODE 3";
LCO 3.4.5, "RCS Loops-MODE 4";
LCO 3.4.7, "RCS Loops-MODE 5, Loops Not Filled";
LCO 3.9.4, "Decay Heat Removal (DHR) and Coolant Circulation-High Water Level" (MODE 6); and
LCO 3.9.5, "Decay Heat Removal (DHR) and Coolant Circulation-Low Water Level" (MODE 6).

Forced circulation is implicitly required in MODES 1 and 2 in order to prevent a Reactor Protection System actuation (Ref. LCO 3.3.1).

ACTIONS

A.1 and A.2

If one DHR loop is inoperable and neither OTSG is OPERABLE, redundant heat removal capability is lost. Action must be initiated to restore a second DHR loop or OTSG to OPERABLE status. Either Required Action A.1 or Required Action A.2 will restore redundant decay heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two heat removal paths.

B.1 and B.2

This Condition is not entered when using the allowance in the Note to the LCO to de-energize all DHR pumps.

If no DHR loop is OPERABLE or in operation, all operations involving the reduction of RCS boron concentration must be suspended and action to restore a DHR loop to OPERABLE status and operation must be initiated immediately. Boron dilution requires forced circulation for proper mixing, and

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

the margin to criticality must not be reduced in this type of operation. The immediate Completion Time reflects the importance of maintaining operation for decay heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification every 12 hours that one DHR loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, and ensures that forced flow is providing heat removal. The 12 hour Frequency has been shown by operating practice to be sufficient to regularly assess degradation. In addition, control room indication and alarms indicate loop status and will typically alert operations personnel to anomalous flow/loss of flow should this occur.

SR 3.4.6.2

Verifying an OTSG is OPERABLE ensures that redundant heat removal paths are available if the second DHR loop is not OPERABLE. This SR is accomplished by verifying the capability of the OTSG to act as a viable decay heat sink. This requires the flow paths for feeding the OTSG through the high (EFW) nozzles and steaming the generator are aligned. A minimal level is recommended but is not required in this condition. Conversely, a secondary side water level of 95% and the capability to feed via the low (MFW) nozzles will ensure adequate decay heat removal and natural circulation. The 7 day Frequency has been shown by operating practice to be sufficient to regularly assess degradation. If both DHR loops are OPERABLE, this Surveillance is not required. However, either SR 3.4.6.2 or SR 3.4.6.3 must be performed within the specified Frequency in order to verify availability/OPERABILITY of the back-up heat removal path.

SR 3.4.6.3

Verification that the second DHR pump is OPERABLE ensures that redundant paths for heat removal are available. The requirement also ensures that the additional loop can be

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.6.3 (continued)

placed in operation if needed to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying correct breaker alignment and power available to the required pumps. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience. If an OTSG is OPERABLE, this Surveillance is not required. However, either SR 3.4.6.2 or SR 3.4.6.3 must be performed within the specified Frequency to verify availability/OPERABILITY of the back-up heat removal path.

REFERENCES

1. B&W Document 51-1223370-01, "Minimum OTSG Level for Natural Circulation." (FPC Calculation M93-0012, R1)

BASES

BACKGROUND (continued)

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at ambient containment pressure in an RCS overpressure transient, if the relieving requirements of the maximum credible LTOP transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow of the limiting LTOP transient and maintaining pressure below LTOP limits. The required vent capacity may be provided by one or more vent paths.

For an RCS vent to meet the flow capacity, it requires removing a pressurizer safety valve, or similarly establishing a vent by removing an OTSG primary side manway cover or primary side handhole cover, or other vents as determined to be sufficient. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

Analyses (Ref. 3) demonstrate that the reactor vessel can be adequately protected against overpressurization transients during shutdown. At 264°F and below, overpressure prevention is provided by an OPERABLE PORV and a restricted coolant level in the pressurizer or by a depressurized RCS and a sufficient size RCS vent.

The actual temperature at which the pressure in the P/T limit curve can fall below the PORV setpoint increases as vessel material toughness decreases due to neutron embrittlement. Each time the P/T limit curves are revised, the LTOP System will be re-evaluated to ensure that its functional requirements can still be met with the PORV and pressurizer level method or the depressurized and vented RCS condition.

Transients that are capable of overpressurizing the RCS have been identified and evaluated (Ref. 4). These transients relate to either mass input or heat input: actuating the HPI System, discharging the CFTs, energizing the pressurizer heaters, failing the makeup control valve open, losing decay heat removal, starting a reactor coolant pump (RCP) with a

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

large temperature mismatch between the primary and secondary coolant systems, and adding nitrogen to the pressurizer.

HPI actuation and CFT discharge are the transients that result in exceeding P/T limits within < 10 minutes, in which time no operator action is assumed to take place. In the rest, operator action after that time precludes overpressurization. The analyses demonstrate that the time allowed for operator action is adequate, or the events are self limiting and do not exceed LTOP limits.

The following are required during the LTOP MODES to ensure that transients do not occur, which either of the LTOP overpressure protection means cannot handle:

a. Deactivating all but one makeup pump;

b. Deactivating HPI; and

c. Immobilizing CFT discharge isolation valves in their closed positions, when CFT pressure is greater than the PTLR limit.

The Reference 3 analyses demonstrate the PORV can maintain RCS pressure below limits when only one makeup pump is actuated. Consequently, the LCO allows only one makeup pump to be OPERABLE in the LTOP MODES.

Inadvertent actuation of HPI can cause the RCS pressure to exceed the LTOP limits determined by Reference 3 sooner than the 10 minutes allowed. Consequently, HPI must be deactivated by assuring that an inadvertent HPI actuation can not inject water into the RCS through the HPI valves.

The isolated CFTs must have their discharge valves closed and the valve power breakers in their open positions. The analyses show the effect of CFT discharge is over a narrower RCS temperature range (208°F and below) than that of the LCO (264°F and below).

Analyses performed per Reference 1 established the temperature of LTOP Applicability at 263°F at the vessel quarter-t location. The LTOP enable temperature of ≤ 264°F includes correction for instrument uncertainty. The vessel materials were assumed to have a neutron irradiation accumulation equal to 32 effective full power years (EFPYs) of operation and plant operation is assumed to be in compliance with the RCS heatup and cooldown limitations of

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

LCO 3.4.3. In addition, Reactor Coolant Pump (RCP) operation is assumed to be restricted to greater than 85°F for the first two pumps, and greater than 220°F for pump three. Pump four operation is not considered for LTOP. During plant heatup, the vessel metal temperature lags the reactor coolant temperature. Stopping the Reactor Coolant System heatup and holding for a period of 90 minutes allows the vessel metal temperature at the quarter-t location to stabilize to the reactor coolant temperature.

This LCO will deactivate the HPI actuation when the RCS temperature is ≤ 264°F. The consequences of a small break LOCA in LTOP MODE 4 are consistent with those discussed in the bases for LCO 3.5.3, "ECCS-Shutdown," by having a maximum of one makeup pump OPERABLE for the required one OPERABLE ECCS train.

Reference 3 contains the acceptance limits that satisfy the LTOP requirements. These limits, in combination with the limitations of LCO 3.4.3, and administrative restrictions on RCP operation, provide the assurance that the reactor vessel is protected from exceeding the requirements of ASME Code Case N-514. Any change to the RCS operation or design must be evaluated against these analyses to determine the impact of the change on the LTOP acceptance limits.

PORV Performance

Analyses (Ref. 3) show that the vessel is protected when the PORV is set to open at ≤ 458 psig. The PORV setpoint at or below the derived limit ensures the requirements of ASME Code Case N-514 (Reference 1) will be met. The PORV lift setpoint limit of ≤ 454 psig includes correction for instrument uncertainty.

The PORV setpoint will be re-evaluated for compliance when the revised P/T limits conflict with the LTOP analysis limits. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to embrittlement induced by neutron irradiation. Revised P/T limits are determined using neutron fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The Bases for LCO 3.4.3 discuss these examinations.

The PORV is considered an active component. Therefore, its failure represents the worst case LTOP single active failure.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Pressurizer Level Performance

Analyses of operator response time show that the pressurizer level must be maintained ≤ 160 inches to provide the 10 minute action time for correcting transients. (Ref. 3) The pressurizer level limit of ≤ 155 inches includes correction for instrument uncertainties.

The pressurizer level limit will also be re-evaluated for compliance each time P/T limit curves are revised based on the results of the vessel material surveillance.

RCS Vent Performance

With the RCS depressurized, analyses show a vent of 0.75 square inches is capable of mitigating the transient resulting from full opening of the makeup control valve while the makeup pump is providing RCS makeup. The capacity of a vent this size is greater than the flow resulting from this credible transient.

The RCS vent size will also be re-evaluated for compliance each time P/T limit curves are revised based on the results of the vessel material surveillance.

The vent is passive and is not subject to active failure.

(continued)

BASES

LCO

The LCO requires an LTOP System OPERABLE with a limited coolant input capability and a pressure relief capability. To limit coolant input, the LCO requires only one makeup pump OPERABLE, the HPI deactivated, and the CFT discharge isolation valves closed and immobilized. For pressure relief, it requires either the pressurizer coolant at or below a maximum level and the PORV OPERABLE with a lift setting at or below the LTOP limit or the RCS depressurized and a vent established.

NOTE: The limits and values presented in this LCO for the PORV lift setpoint, enable temperature, and pressurizer level are corrected for instrument uncertainty. The instrumentation to be used by plant operators to assure compliance with these limits and values are specified in approved plant operating procedures.

The pressurizer is available with a coolant level ≤ 155 inches.

The PORV is OPERABLE when its block valve is open, its lift setpoint is set at ≤ 454 psig and testing has proven its ability to open at that setpoint, and motive power is available to the PORV and the PORV control circuits.

For the depressurized RCS, an RCS vent is OPERABLE when open with an area of at least 0.75 square inches.

APPLICABILITY

This LCO is applicable in MODE 4 when RCS temperature is ≤ 264°F, in MODE 5, and in MODE 6 when the reactor vessel head is not completely detensioned. The Applicability temperature of 264°F is established by analyses in accordance with Reference 1. With the vessel head completely detensioned, overpressurization is not possible. The vessel head is completely detensioned when the pre-stress has been relieved from all of the studs, and the nuts are free spinning.

The Applicability is modified by a Note stating that CFT isolation is only required when the CFT pressure is more than or equal to the maximum RCS pressure for the existing RCS temperature, as allowed in LCO 3.4.3. This Note permits the CFT discharge valve surveillance performed only under these pressure and temperature conditions.

(continued)

BASES

ACTIONS

Allowable times are specified in the LCO to implement the actions and controls described below. These times range from immediately to 12 hours. The times are based on operational and industry experience and regulatory recommendations. The times are intended to balance the time necessary to accomplish the actions and the likelihood of experiencing a limiting transient during the action.

A.1 and B.1

With two or more makeup pumps capable of injecting into the RCS or if the HPI is activated, immediate actions are required to render the other pump(s) inoperable or to deactivate HPI. Emphasis is on immediate deactivation because inadvertent injection with one or more HPI pump OPERABLE is the event of greatest significance, since it causes the greatest pressure increase in the shortest time.

Required Action A.1 is modified by a Note that permits two pumps capable of RCS injection for ≤ 15 minutes to allow for pump swaps.

The deactivation of HPI is accomplished by assuring that an inadvertent HPI actuation can not inject water into the RCS through the HPI valves. This may be accomplished by combinations of equipment as determined appropriate for the existing plant conditions such as, disabling all HPI valves or disabling all Makeup pumps. If powered components are used to accomplish deactivation, power should be removed to assure positive lockout.

C.1, D.1, and D.2

An unisolated CFT requires isolation within 1 hour only when the CFT pressure is at or greater than the maximum RCS pressure for the existing temperature allowed in LCO 3.4.3.

If isolation is needed and cannot be accomplished in 1 hour, Required Action D.1 and Required Action D.2 provide two options, either of which must be performed in 12 hours. By increasing the RCS temperature to > 208°F, the CFT pressure of 600 psig cannot exceed the LTOP limits if both tanks are fully injected. Depressurizing the CFTs below the LTOP limit of 454 psig also prevents exceeding the LTOP limits in the same event.

(continued)

BASES

ACTIONS (continued)

E.1, F.1 and F.2

With the pressurizer level more than 155 inches, the time for operator action in a pressure increasing event is reduced. The postulated event most affected in the LTOP MODES is failure of the makeup control valve, which fills the pressurizer relatively rapidly. Restoration is required within 1 hour.

If restoration within 1 hour cannot be accomplished, Required Actions F.1 and F.2 must be performed within 12 hours. Actions F.1 and F.2 limit the makeup capability by closing the makeup control valve and its isolation valve, which is not required with a high pressurizer level, and permit cooldown and depressurization to continue. When the makeup is isolated, RCS heatup must be stopped because heat addition decreases the reactor coolant density and increases the pressurizer level. Operations such as starting RC pumps and reducing decay heat removal should not be performed when in this condition.

G.1, H.1, and H.2

With the PORV inoperable, overpressure relieving capability is lost, and restoration of the PORV within 1 hour is required. If that cannot be accomplished, the ability of the Makeup System to add water must be limited within the next 12 hours.

If restoration cannot be completed within 1 hour, Required Action H.1 and Required Action H.2 must be performed to limit RCS water addition capability. Makeup is not required to be deactivated since it may be needed to maintain the RCS coolant level. Required Action H.1 and Required Action H.2 require reducing the makeup tank level to 88 inches and deactivating the low low makeup tank level interlock to the borated water storage tank. This makes the available makeup water volume insufficient to exceed the LTOP limit by a makeup control valve full opening.

(continued)

BASES

ACTIONS (continued)

I.1 and I.2

With the pressurizer level above 155 inches and the PORV inoperable or the LTOP System inoperable for any reason other than cited in Condition A through H, the system must be restored to OPERABLE status within 1 hour. When this is not possible, Required Action I.2 requires the RCS depressurized and vented within 12 hours from the time either Condition started.

One or more RCS vents may be used. A vent size of ≥ 0.75 square inches is specified. Such a vent keeps the pressure from full flow of one Makeup pump with a wide open makeup control valve within the LCO limit.

This size RCS vent cannot maintain RCS pressure below LTOP limits if the HPI or CFT systems are inadvertently actuated. Therefore, verification of the deactivation of two Makeup pumps, HPI injection, and the CFTs must accompany the depressurizing and venting. Since these systems are required deactivated by the LCO, SR 3.4.11.1, SR 3.4.11.2, and SR 3.4.11.3 require verification of their deactivated status every 12 hours.

SURVEILLANCE REQUIREMENTS

The following surveillance requirement frequencies are shown by operating experience and industry accepted practice to be sufficient to regularly assess conditions for potential degradation and to verify operation within the requirements.

SR 3.4.11.1, SR 3.4.11.2, and SR 3.4.11.3

Verifications must be performed that only one makeup pump is capable of injecting into the RCS, the HPI is deactivated, and the CFT discharge isolation valves are closed and immobilized. These Surveillances ensure the minimum coolant input capability will not create an RCS overpressure condition to challenge the LTOP System. The Surveillances are required at 12 hour intervals.

A Note modifies SR 3.4.11.3 by only requiring this Surveillance when CFT isolation is required.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.11.4

Verification of the pressurizer level at ≤ 155 inches by observing control room or other indications ensures a cushion of sufficient size is available to reduce the rate of pressure increase from potential transients.

The 30 minute Surveillance Frequency during heatup and cooldown must be performed for the LCO Applicability period when temperature changes can cause pressurizer level variations. This Frequency may be discontinued when the ends of these conditions are satisfied, as defined in plant procedures. Thereafter, the Surveillance is required at 12 hour intervals.

A Note modifies the SR by not requiring the Surveillance when complying with LCO 3.4.11.b.

SR 3.4.11.5

Verification that the PORV block valve is open ensures a flow path to the PORV. This is required at 12 hour intervals.

A Note modifies the SR by not requiring the Surveillance when complying with LCO 3.4.11.b.

SR 3.4.11.6

When stipulated by LCO 3.4.11.b, the RCS vent of at least 0.75 square inch must be verified open for relief protection. For an unlocked vent opening, the Frequency is every 12 hours. For a locked vent opening in the RCS, the required Frequency is every 31 days.

A Note modifies the SR by requiring the Surveillance when complying with LCO 3.4.11.b.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.11.7

A CHANNEL FUNCTIONAL TEST is required within 12 hours before or after decreasing RCS temperature to ≤ 264°F and every 31 days thereafter to ensure the setpoint is proper for using the PORV for LTOP. PORV actuation is not needed, as it could depressurize the RCS.

The 12 hour frequency considers the unlikelihood of a low temperature overpressure event during the time.

SR 3.4.11.8

The performance of a CHANNEL CALIBRATION is required every 24 months. The CHANNEL CALIBRATION for the LTOP setpoint ensures that the PORV will be actuated at the appropriate RCS pressure by verifying the accuracy of the instrument string. The calibration can only be performed in shutdown. The frequency considers the refueling cycle.

SR 3.4.11.9

Verification that the PORV is selected to the low range setpoint ensures the overpressure protection flow path through the PORV. This is required at 12 hour intervals.

A Note modifies the SR by not requiring the Surveillance when complying with LCO 3.4.11.b.

(continued)

BASES

REFERENCES

1. ASME Code Case N-514, "Low Temperature Overpressure Protection Section XI, Division 1".

2. Generic Letter 88-11, "NRC Position on Radiation Embrittlement of Reactor Vessel Materials and its Impact on Plant Operations".

3. FPC Calculation F98-0013, "CR-3 32 EFPY P/T Limits".

4. B&W Nuclear Services (FTI) Document 51-1176431-01, "Crystal River 3 Reactor Vessel Low Temperature Overpressure Protection (LTOP)".

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

10 CFR 50, Appendix A, GDC 30, (Ref. 1) requires means be provided for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Leakage detection systems must have the capability to detect reactor coolant pressure boundary (RCPB) degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE.

The containment sump collects unidentified LEAKAGE and is instrumented to alarm on increasing level and has the capability to detect a leakage rate of 1 gpm in less than 1 hour. This sensitivity is acceptable for detecting increases in unidentified LEAKAGE.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. Instrument sensitivities of 10^{-9} μCi/cc radioactivity for particulate monitoring and of 10^{-6} μCi/cc radioactivity for gaseous monitoring are adequate for these leakage detection systems. The particulate monitoring channel is capable of detecting a change in RCS leak rate of 1 gpm within one hour based on activity levels assumed in the environmental report (0.1% failed fuel). The predominant nuclide of detection for the particulate channel is Rb-88. The gaseous channel requires significantly more time to detect the same change in RCS leak rate (approximately 14 hours). This is due to the relatively long half-life of its predominant nuclide of detection, Xe-133.

Other installed instrumentation such as RB pressure and Containment Cooling Fan condensate flow also indicate leakage into containment. These are potentially valuable

(continued)

BASES

BACKGROUND (continued)

diagnostic tools but they are not capable of accurately detecting leak rates of 1 gpm and below. As such, they are not acceptable leakage detection systems for the purposes of satisfying this LCO.

APPLICABLE SAFETY ANALYSES

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area is very important. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should a leak occur.

Leakage detection capability is also a fundamental aspect of the "leak before break" concept of piping design. This concept is based on the premise that main loop RCS piping will not fail catastrophically, but will leak prior to the failure. Demonstrating this to be true (shown probabilistically) and that this leakage can be detected, allows the dynamic effects associated with RCS pipe breaks to be excluded from the design basis of the RCS (Ref. 3).

RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement.

LCO

One method of protecting against large RCS LEAKAGE derives from the instruments ability to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition when RCS LEAKAGE indicates possible RCPB degradation. OPERABILITY of the atmospheric radiation monitors include the proper operation of the sample pump. This pump is common to both monitors such that its failure can affect the plant's capability to monitor the containment atmosphere.

(continued)

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS-Operating

BASES

BACKGROUND

The function of the ECCS is to provide core cooling to ensure that the reactor core is protected after any of the following accidents:

1. Loss of coolant accident (LOCA);
2. Steam generator tube rupture (SGTR); and
3. Steam line break (SLB).

There are two modes of ECCS operation: injection and recirculation. In the injection phase, all injection is initially added to the Reactor Coolant System (RCS) from the borated water storage tank (BWST). This injection flow is added via the RCS cold legs and core flood nozzles to the reactor vessel. After the BWST has been depleted to $\leq$ 15 feet but > 7 feet, the ECCS recirculation phase is entered as the ECCS suction is manually transferred to the reactor building emergency sump.

Two redundant, 100% capacity trains are provided. Each train consists of high pressure injection (HPI) and low pressure injection (LPI) subsystems. In MODES 1, 2, and 3, both trains must be OPERABLE. This ensures that 100% of the core cooling requirements can be provided even in the event of a single active failure.

Certain size small break LOCA scenarios require emergency feedwater to maintain steam generator cooling until core decay heat can be removed solely by ECCS cooling.

A suction header supplies water from the BWST or the reactor building emergency sump to the ECCS pumps. Separate piping supplies each train. Each HPI subsystem discharges into each of the four RCS cold legs between the reactor coolant pump and the reactor vessel. Each LPI subsystem discharges into its associated core flood nozzle on the reactor vessel and discharges into the vessel downcomer area. Control valves are set to balance the HPI flow to the RCS. This flow balance directs sufficient flow to the core to meet the analysis assumptions following a small break LOCA in one of the RCS cold legs near an HPI nozzle.

The HPI pumps are capable of discharging to the RCS at an RCS pressure above the opening setpoint of the pressurizer

(continued)

BASES

BACKGROUND (continued)

safety valves. The LPI pumps are capable of discharging to the RCS at an RCS pressure of approximately 200 psia. When the BWST has been nearly emptied, the suction for the LPI pumps is manually transferred to the reactor building emergency sump. The HPI pumps cannot take suction directly from the sump. If HPI is still needed, a cross connect from the discharge side of the LPI pump to the suction of the HPI pumps would be opened. This is known as "piggy backing" HPI to LPI, and enables continued HPI to the RCS, if needed, after the BWST is emptied to the switchover point.

In the long term cooling period, flow paths in the LPI System can be established to preclude the possibility of boric acid in the core region reaching an unacceptably high concentration. LPI can be aligned to provide for two active methods of boron dilution. In one method, the decay heat system drop line is aligned to the RB sump to allow gravity feed from the hot leg. The other method consists of aligning the Auxiliary Pressurizer Spray to provide injection of boron dilute water into the hot leg.

Both active methods may be affected by a failure of Engineered Safeguards Motor Control Center ES MCC 3AB. However, due to conservatisms inherent in the analyses which demonstrated the effectiveness of these methods, combined with FPC's development of restoration procedures, reasonable assurance exists that FPC can restore an active method before boron can pose a challenge to long-term core cooling. As such, an exemption from the requirements of 10CFR50 Appendix K, "Single Failure Criterion," with regard to post-LOCA boron precipitation control was granted (Ref. 7).

HPI also functions to supply borated water to the reactor core following increased heat removal events, such as large SLBs.

During a large break LOCA, RCS pressure will decrease to < 200 psia in < 20 seconds. The ECCS is actuated upon receipt of an Engineered Safeguards Actuation System (ESAS) signal. The actuation of safeguard loads is accomplished in a programmed time sequence. If offsite power is available, the safeguard loads start immediately (in the programmed sequence). If offsite power is not available, the engineered safety feature (ESF) buses shed normal operating loads and are connected to the diesel generators. Safeguard loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, and pump starting determines the time required

(continued)

BASES

BACKGROUND (continued)

before pumped flow is available to the core following a LOCA.

The active ECCS components, along with the passive core flood tanks (CFTs) and the BWST covered in LCO 3.5.1, "Core Flood Tanks (CFTs)," and LCO 3.5.4, "Borated Water Storage Tank (BWST)," provide the cooling water necessary to meet 10 CFR 50.46 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 1), will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. Core is maintained in a coolable geometry; and

e. Adequate long term core cooling capability is maintained.

Both HPI and LPI subsystems are assumed to be OPERABLE in the large break LOCA analysis at full power (Ref. 2). This analysis establishes a minimum required flow for the HPI and LPI pumps, as well as the minimum required response time for their actuation. The HPI pump is credited in the small break LOCA analysis. This analysis establishes the flow and discharge head requirements at the design point for the HPI pump. The SGTR and SLB analyses also credit the HPI pump but are not limiting in their design.

The large break LOCA event with a coincident (with reactor trip) loss of offsite power and a single failure (disabling one ECCS train) establishes the majority of OPERABILITY requirements for the ECCS. During the blowdown phase of a

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or CONTROL ROD assembly insertion for small breaks. Following depressurization, emergency cooling water is injected into the reactor vessel core flood nozzles, then flows into the downcomer, fills the lower plenum, and refloods the core.

The LCO ensures that an ECCS train will deliver sufficient water to match decay heat boiloff rates soon enough to minimize core uncovery for a large break LOCA. It also ensures that the HPI pump will deliver sufficient water for a small break LOCA and provide sufficient boron to maintain the core subcritical following the small break LOCA or an SLB.

In the small break LOCA analyses, HPI is not credited until 67 seconds after actuation of the ESAS signal and LPI flow is not credited until RCS pressure drops below the pump's shutoff head. In the large break LOCA analyses, HPI is not credited at all and LPI is not credited until 35 seconds after actuation of the ESAS signal. These assumptions are conservative considering a loss of offsite power and the associated time delays in startup and loading of the emergency diesel generator (EDG).

The ECCS trains satisfy Criterion 3 of the NRC Policy Statement.

LCO

In MODES 1, 2, and 3, two independent (and redundant) ECCS trains are required to ensure that at least one is available, assuming a single active failure in the other train. With one ECCS train inoperable, the system is still capable of mitigating an event, providing a concurrent single failure does not occur. Hence, the 72 hour ACTION addressing a loss of redundancy is appropriate.

(continued)

BASES

LCO (continued)

Not all portions of the HPI flow path satisfy the independence criteria discussed above. Specifically, the HPI flow path downstream of the HPI/Makeup pumps is not separable into two distinct trains, and is therefore, not independent. This conclusion is based upon analysis which shows, that in the event of a postulated break in the HPI injection piping, injection flow is required through a minimum of three (3) injection legs, assuming one pump operation, or through a minimum of two (2) injection legs, assuming two HPI pump operation. When considering the impact of inoperabilities in this portion of the system, the same concept of maintaining single active failure protection must be applied. When components become inoperable, an assessment of the HPI systems ability to perform its safety function must be performed. If the system can continue to perform its safety function, without assuming a single active failure, then the 72 hour loss of redundancy ACTION is appropriate. If the inoperability renders the system, as is, incapable of performing its safety function, without postulating a single active failure, then the plant is in a condition outside the safety analysis and must enter LCO 3.0.3 immediately.

In MODES 1, 2, and 3, an ECCS train consists of an HPI subsystem and an LPI subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the BWST upon an ESAS signal and manually transferring suction to the reactor building emergency sump.

During an event requiring ECCS actuation, a flow path is provided to ensure an abundant supply of water from the BWST to the RCS via the HPI and LPI pumps and their respective discharge flow paths to each of the four cold leg injection nozzles and the reactor vessel. In the long term, this flow path may be manually transferred to take its supply from the reactor building emergency sump and to supply its flow to the RCS via two paths, as described in the Background section.

The flow path for each train must maintain its designed degree of independence to ensure that no single active failure can disable both ECCS trains.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the ECCS train OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements in the lower MODES. The HPI pump performance is based on the small break LOCA, which establishes the pump performance curve and is less dependent on power. MODES 2 and 3 requirements are bounded by the MODE 1 analysis.

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.6, "RCS Loops-MODE 5, Loops Filled," and LCO 3.4.7, "RCS Loops-MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Decay Heat Removal and Coolant Circulation-High Water Level," and LCO 3.9.5, "Decay Heat Removal and Coolant Circulation-Low Water Level."

(continued)

BASES

ACTIONS

A.1

With one or more ECCS trains inoperable and at least 100% of the flow equivalent to a single OPERABLE ECCS train available, the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on NRC recommendations (Ref. 3) that are based on a risk evaluation and is a reasonable time for many repairs.

An ECCS train is inoperable if it is not capable of delivering the design flow to the RCS.

The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one component in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of two different components, each in a different train, necessarily result in a loss of function for the ECCS. The intent of this Condition is to maintain a combination of equipment such that the safety injection (SI) flow equivalent to 100% of a single train remains available. This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable.

For example, removing a train of the recirculation line to the RB sump or the entire bank of valves for maintenance does not render the HPI System inoperable, given the diverse ability to recirculate to the Makeup Tank. HPI satisfies Criterion 3 of the NRC Policy Statement which addresses SSCs that are part of the primary success path, and which function or actuate to mitigate a design basis accident or transient challenging a fission product barrier. Since this recirculation line supports piggyback operation in long-term cooling, and piggyback operation is not a primary success path, LCO 3.5.2 need not be entered when this recirculation path is not available.

An event accompanied by a loss of offsite power and the failure of an EDG can disable one ECCS train until power is restored. A reliability analysis (Ref. 3) has shown the risk of having one full ECCS train inoperable to be sufficiently low to justify continued operation for 72 hours.

With one or more components inoperable such that the flow equivalent to a single OPERABLE ECCS train is not available, the facility is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be immediately entered.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the inoperable components cannot be returned to OPERABLE status within the associated Completion Times, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and at least MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing.

These valves include valves in the main flow paths and the first normally closed valve in a branch line. In lieu of the first normally closed valve in the branch line, credit may be taken for verifying valve position of another valve downstream, providing the isolation of the flow path is achieved. Verifying correct valve alignment of valves immediately downstream of an unsecured valve still assures isolation of the flow path. There are several exceptions for valve position verification due to the low potential for these types of valves to be mispositioned. The valve types which are not verified as part of this SR include vent or drain valves, relief valves, instrumentation valves, check valves, and sample line valves. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve will automatically reposition within the proper stroke time. For a power operated valve to be considered "locked, sealed, or otherwise secured", the component must be electrically and physically restrained. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 (continued)

The 31 day frequency is appropriate because the valves are operated under administrative control, and an inoperable valve position would only affect a single train. This frequency has been shown to be acceptable through operating experience.

SR 3.5.2.2

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by Section XI of the American Society of Mechanical Engineers (ASME) Code (Ref. 4). This type of testing may be accomplished by measuring the pump's developed head at only one point of the pump's characteristic curve and this point may be anywhere on the curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant accident analysis. SRs are specified in the Inservice Testing Program, which encompasses Section XI of the ASME Code. Section XI of the ASME Code provides the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.3 and SR 3.5.2.4

These SRs demonstrate that each automatic ECCS valve that is not locked, sealed, or otherwise secured in position, actuates to its required position on an actual or simulated ESAS signal and that each ECCS pump starts on receipt of an actual or simulated ESAS signal. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 24 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of the ESAS testing, and equipment performance is monitored as part of the Inservice Testing Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.5

Verification of the positions of the listed valves in the HPI flowpath ensures adequate flow resistance in the overall system and the individual HPI lines. Maintenance of adequate flow resistance and pressure drop in the piping system for each injection point is necessary in order to: (1) provide the proper flow split between injection points in accordance with the assumptions used in the ECCS LOCA analyses; (2) provide an acceptable level of total ECCS flow to all injection points equal to or above values assumed in the ECCS LOCA analyses; (3) ensure adequate cooling flow to the HPI pump mechanical seals; and (4) prevent HPI pump flow from exceeding 600 gpm when the system is in its minimum resistance configuration (600 gpm is the maximum HPI pump flow rate assumed in design calculations associated with Emergency Diesel Generator loading, ECCS pump available NPSH, and makeup tank (MUT-1) allowable overpressure versus level). This 24 month Frequency is acceptable based on consideration of the design reliability of valves that are locked, sealed, or otherwise secured in position.

Verification of correct valve position will be accomplished by assuring the mechanism that locks, seals or secures the valves is intact. If the stop check valves or throttle valves are repositioned, the valves must be returned to their correct position and then secured. This "as-left" position verification ensures the HPI flow assumptions in the accident analysis are maintained.

SR 3.5.2.6

This Surveillance ensures that the flow controllers for the LPI throttle valves will automatically control the LPI train flow rate in the desired range and prevent LPI pump runout as RCS pressure decreases after a LOCA. The 24 month Frequency is acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.7

Periodic inspections of the reactor building emergency sump suction inlet ensure that it is unrestricted and stays in proper operating condition. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and to preserve access to the location. This Frequency has been found to be sufficient to detect abnormal degradation and has been confirmed by operating experience.

REFERENCES

1. 10 CFR 50.46.

2. FSAR, Section 6.1.

3. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

4. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI, Inservice Inspection, Article IWP-3000.

5. Deleted.

6. FSAR, Section 4.3.10.1.

7. Letter from NRC to FPC, 3N1098-15, dated October 29, 1998, "Issuance of Exemption from the Requirements of 10 CFR 50, Appendix K, Section I.D.1 - Crystal River Unit 3 (TAC No. M99892)".

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.4 Borated Water Storage Tank (BWST)

BASES

BACKGROUND

The BWST supports the ECCS and the Reactor Building (RB) Spray System by providing a source of borated water for ECCS and RB spray pump operation. In addition, the BWST supplies borated water to the refueling canal for refueling operations.

The BWST supplies both ECCS trains, each by a separate, redundant supply header. Each header also supplies one train of the RB Spray System. Normally open, motor operated isolation valves (DHV-34, DHV-35) are provided in the headers. They allow the operator to isolate the BWST from the Low Pressure Injection (LPI) and RB spray pumps after the pump suction has been transferred to the reactor building emergency sump following depletion of the BWST during a loss of coolant accident (LOCA). Two motor operated isolation valves (MUV-58, MUV-73) provide this same isolation capability for the High Pressure Injection (HPI) system. One of these valves is normally maintained open dependent upon which Makeup/HPI pumps are ES selected. This practice is dictated by the widely-differing response times of the pumps and valves and ensures an immediate suction source to these pumps in the event of an ESFAS actuation. Use of a single BWST to supply both ECCS trains is acceptable because the BWST is a passive component and passive failures are not assumed in the analysis of Design Basis Events (DBEs) to occur coincidentally with the Design Basis Accident (DBA).

This LCO ensures that:

a. The BWST contains sufficient borated water to support the ECCS during the injection phase;

b. Sufficient water volume exists in the containment sump to support continued operation of the ECCS and RB spray pumps at the time of transfer to the recirculation mode of cooling; and

(continued)

BASES

BACKGROUND (continued)

c. The reactor remains subcritical following a LOCA or Steam Line Break (SLB).

Insufficient water inventory in the BWST could result in insufficient cooling capacity of the ECCS, inadequate NPSH for ECCS and RB Spray pumps, insufficient RB heat removal/pressure control and insufficient iodine removal capability when the transfer to the recirculation mode occurs.

Improper boron concentrations could result in a reduction of SHUTDOWN MARGIN or excessive boric acid precipitation in the core following a LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside containment.

APPLICABLE SAFETY ANALYSES

During accident conditions, the BWST is the source of borated water to the high pressure injection (HPI), low pressure injection (LPI), and RB spray pumps. As such, it provides core cooling and replacement inventory, containment cooling and depressurization, and is a source of negative reactivity for reactor shutdown. The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of Specifications B 3.5.2, "ECCS-Operating," and B 3.6.6, "Reactor Building Spray and Containment Cooling Systems."

The limits on volume of ≥ 415,200 gallons and ≤ 449,000 gallons are based on several factors. Sufficient deliverable volume must be available to provide at least 20 minutes of full flow of all ECCS pumps prior to the transfer to the reactor building emergency sump for recirculation. Twenty minutes gives the operator adequate time to prepare for switchover to reactor building emergency sump recirculation.

A second factor that affects the minimum required BWST volume is the ability to support continued ECCS pump operation after the manual transfer to recirculation occurs. When ECCS pump suction is transferred to the sump, there must be sufficient water in the sump to ensure adequate net

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.4.2

Verification every 7 days that the BWST contained volume is within the required range ensures that a sufficient initial supply is available for injection and to support continued ECCS pump operation on recirculation. Since the BWST volume is normally stable and provided with a Low Level alarm, a 7 day Frequency has been shown to be appropriate through operating experience.

SR 3.5.4.3

Verification every 31 days that the boron concentration of the BWST fluid is within the required band ensures that the reactor will remain subcritical following a small break LOCA or SLB. Since the BWST volume is normally static, mechanisms which would cause a change in concentration are limited and a 31 day sampling Frequency is appropriate.

The Frequency is adequate to identify changes that occur from mechanisms such as stratification or in-leakage. Sampling within 12 hours following a 4000 gallon volume increase allows time to recirculate the tank volume and will identify whether in-leakage or addition from another source has caused the boron concentration to be outside the required limit.

REFERENCES

1. FSAR, Section 6.4.2 and Table 6-12.

2. Decay Heat Removal System Design Basis Document.

BASES (continued)

LCO

Containment OPERABILITY is maintained by limiting leakage to less than the acceptance criteria of the Containment Leakage Rate Testing Program. Compliance with this LCO will ensure I a 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 containment air lock (LCO 3.6.2) and purge valves with resilient seals (LCO 3.6.3) are not specifically part of the acceptance criteria of SR 3.6.1.1. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the total leakage exceeds the acceptance criteria of the Containment Leakage Rate Testing Program.

APPLICABILITY

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

ACTIONS

A.1

In the event containment is inoperable, containment 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 containment during MODES 1, 2, 3, and 4. This time period also ensures the probability of an accident (requiring containment OPERABILITY) occurring during periods when containment is inoperable is minimal.

B.1 and B.2

If containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock and purge valve with resilient seal leakage limits for SR 3.6.2.1 and 3.6.3.6 does not constitute a failure of this Surveillance unless the contribution from these penetrations causes overall Type A, B, and C leakage to exceed limits. SR Frequencies are as required by the Containment Leakage Rate Testing Program. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

SR 3.6.1.2

This SR ensures that the structural integrity of the containment will be maintained in accordance with the provisions of the Containment Inspection Program. Testing and Frequency are in accordance with Subsections IWE and IWL of the 1992 ASME Code and 10 CFR 50.55a.

Abnormal degradation shall be determined by engineering evaluation. In the event abnormal degradation is detected, a Special Report shall be submitted in accordance with ITS 5.7.2.b. The impact of large-scale tendon degradation should also be evaluated with respect to Containment OPERABILITY. In this context, containment structural integrity is analogous to containment OPERABILITY.

(continued)

BASES

REFERENCES

1. 10 CFR 50, Appendix J, Option B

2. FSAR, Sections 14.2.2

3. FSAR, 5.2.1.1

4. 1992 Edition of the ASME Boiler and Pressure Vessel Code, Section XI, Subsections IWE and IWL.

5. 10 CFR 100.

6. NEI 94-01, Revision 0, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J"

7. ANSI/ANS-56.8 1994, "American National Standard for Containment System Leakage Testing Requirement"

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Locks

BASES

BACKGROUND

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

Each air lock is nominally a right circular cylinder, 10 ft in diameter, with a door at each end. The doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and is tested to verify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. Therefore, closure of a single door supports containment OPERABILITY. Each of the doors contain two gasketed seals and local leakage rate testing capability to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door).

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

The containment air locks form part of the containment pressure boundary. Their integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analysis. All leakage rate requirements are in conformance with 10 CFR 50, Appendix J, Option B (Ref. 1).

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Reactor Building Spray and Containment Cooling Systems

BASES

BACKGROUND

The Reactor Building (RB) Spray and Containment Cooling Systems are Engineered Safeguards (ES) systems. They provide containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure and the iodine removal capability of the spray reduces the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA), to within limits. The Reactor Building Spray and Containment Cooling Systems were designed considering the applicable proposed 10 CFR 50.34, Appendix A, "General Design Criteria for Nuclear Power Plant Construction Permits", (Ref. 1) criteria. Refer to FSAR Section 1.4 for a more detailed description of these design criteria.

Reactor Building (RB) Spray System

The RB Spray System consists of two separate trains of equal capacity, each capable of meeting the design bases. Each train includes an RB spray pump, spray headers, nozzles, valves, and piping. Each train is powered from a separate ES bus. The borated water storage tank (BWST) supplies borated water to the RB Spray System during the ECCS injection mode of operation. In the recirculation mode of operation, RB Spray System pump suction is manually transferred from the BWST to the containment sump.

During the injection mode of ECCS operation, the RB Spray System provides a spray of relatively cold borated water into the upper regions of containment to reduce the containment pressure and temperature and to reduce the concentration of fission products in the containment atmosphere. Each header contains nozzles which are arranged to provide maximum "washing" of the RB atmosphere. The headers are located in the RB dome, more than 96 feet above any floor level. Spray nozzles are spaced in the header to give uniform spray coverage of the RB volume above the operating floor with one or both spray header systems in operation. CR-3 iodine removal effectiveness analysis quotes a value of 65.2% for RB volume covered by the spray, based on the location of the uppermost spray ring to the operating floor at elevation 160 feet. In the recirculation mode of operation, water in the reactor building emergency sump is mixed with trisodium phosphate dodecahydrate (TSP-C)

(continued)

BASES

BACKGROUND

Reactor Building Spray System (continued)

in order to raise the pH of the sump water to at least 7.0. Heat is removed from the containment sump water by the decay heat removal (DHR/LPI) coolers. Each train of the RB Spray System provides adequate spray coverage to meet the system design requirements for containment heat removal.

The RB Spray System is actuated automatically by a High-High reactor building pressure signal (30 psig) coincident with a high pressure injection start permit actuation signal. A High reactor building pressure signal (4 psig) opens the RB Spray System pump discharge valves to correspond to a pre-set flowrate while a High-High reactor building pressure signal starts the two RB Spray System pumps.

Containment Cooling System

The Reactor Building (RB) Containment Cooling System consists of three (3) containment cooling units (AHF-1A, 1B, 1C) connected to a common duct suction header with four vertical return air ducts. Each cooling train is equipped with demisters, cooling coils, and an axial flow fan driven by a two speed water cooled electric motor. Each unit connection (two per unit) to the common header is provided with a backpressure damper for isolation purposes.

Each of the three (3) RB Cooling Units (RBCUs) consists of two (2) split banks of four (4) coils on each side. The coils are supplied by a single piping system which allows alignment of either the Nuclear Services Closed Cycle Cooling Water (SW) System (emergency supply) or the Industrial Cooling Water (CI) System (non-emergency supply).

During normal operation, a maximum of two containment cooling units may operate to maintain containment average air temperature less than 130 F (Ref. 3.6.5). With two units operating, the plant has recorded temperatures as high as 129 F. The third unit is on standby and isolated from the operating units by means of the backpressure dampers. Fan/cooler unit AHF-1C is equipped with a transfer switch which allows it to be manually placed to either the "A" or "B" power train to operate in case one of the operating units fails. The containment cooling unit not in use has a manual SW System supply valve closed. This action is taken because the Emergency Diesel Generators have limitations on their electrical capacity. This capacity limitation will not permit more than two RBCUs to be supplied by a SW Pump. Otherwise, the SW Pump could require more power than has been accounted for in the Emergency Diesel Generator loading calculations.

(continued)

BASES

ACTIONS

C.1 (continued)

The 10 day portion of the Completion Time for Required Action C.1 is based upon engineering judgment. It takes into account the low probability of coincident entry into two Conditions in this LCO coupled with the low probability of an accident occurring during this time. Refer to Section 1.3 for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

D.1

With two of the required containment cooling trains inoperable, one of the required containment cooling trains must be restored to OPERABLE status within 72 hours. The components in this degraded condition (both spray trains are OPERABLE or else Condition E is entered) provide iodine removal capabilities and are capable of providing at least 100% of the heat removal needs after an accident. The 72 hour Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the RB Spray System and Containment Cooling System and the low probability of a DBA occurring during this period.

E.1 and E.2

If the Required Actions and associated Completion Times of Condition C or D of this LCO are not met, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1

With two RB spray trains or any combination of three or more RB spray and required containment cooling trains inoperable, the unit is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment for manual, power operated, and automatic valves in the RB spray flow path provides assurance that the proper flow paths will exist for RB Spray 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.

These valves include valves in the main flow paths and the first normally closed valve in a branch line. In lieu of the first normally closed valve in the branch line, credit may be taken for verifying valve position of another valve downstream, providing the isolation of the flow path is achieved. Verifying correct valve alignment of valves immediately downstream of an unsecured valve still assures isolation of the flow path. There are several exceptions for valve position verification due to the low potential for these types of valves to be mispositioned. The valve types which are not verified as part of this SR include vent or drain valves, relief valves, instrumentation valves, check valves, and sample line valves. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve will automatically reposition within the proper stroke time. For a power operated valve to be considered "locked, sealed, or otherwise secured", the component must be electrically and physically restrained. 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.

The 31 day frequency is appropriate because the valves are operated under administrative control, and an inoperable valve position would only affect a single train. This frequency has been shown to be acceptable through operating experience.

SR 3.6.6.2

Operating each required containment cooling train fan unit for ≥ 15 minutes ensures that all trains 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. The 31 day Frequency was developed considering the known reliability of the fan units and controls, the two train redundancy available, and the low probability of a significant degradation of the containment cooling trains

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

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

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that the closure time of each MSIV is in accordance with the limit specified in the Inservice Testing Program. This MSIV closure time is established based upon design specifications for the valves and is consistent with the accident and containment analyses. This Surveillance is normally performed upon returning the plant to operation following a refueling outage, because the MSIVs should not be tested at power since even a part stroke exercise increases the risk of a valve closure with the plant generating power. As the MSIVs are not to be tested at power, they are exempt from the ASME Code, Section XI (Ref. 7) quarterly valve stroke requirements.

The Frequency for this SR is in accordance with the Inservice Testing Program and is based on the typical refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at this Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows delaying testing until MODE 3 in order to establish plant conditions most representative of those under which the acceptance criterion was generated.

(continued)

BASES

REFERENCES

1. Enhanced Design Basis Document for the Main Steam System.

2. FSAR, Section 10.2.1.4.

3. 10 CFR 50, Appendix A, GDC 57.

4. FSAR, Section 14.2.2.1.7.

5. FSAR, Section 14.2.2.2.

6. 10 CFR 100.

7. ASME, Boiler and Pressure Vessel Code, Section XI, Inservice Inspection, Article IWV-3400.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1 (continued)

The Frequency for this SR is in accordance with the Inservice Testing Program. Operating experience has shown that these components usually pass the Surveillance when performed at this Frequency.

REFERENCES

1. FSAR, Section 10.2.1.2.

2. FSAR, Section 7.2.4.2.

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

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B 3.7 PLANT SYSTEMS

B 3.7.5 Emergency Feedwater (EFW) System

BASES

BACKGROUND

The Emergency Feedwater (EFW) System is designed to provide adequate flow to one or both steam generators (OTSGs) for decay heat removal with the generators at the maximum operating pressure of 1050 psig plus suitable margin for post-accident pressure increase (Ref. 1, 2). The principal function of the EFW system is to remove decay heat from the Reactor Coolant System upon the unavailability of normal feedwater supply. This is accomplished by supplying water from the emergency feedwater tank (EFT-2) to the OTSG secondary side via the high nozzles. Steam produced in the OTSGs is condensed in the main condenser via the turbine bypass valves or, if the atmospheric dump valves (ADVs) or main steam safety valves (MSSVs) have actuated, discharged directly to the atmosphere.

The EFW System consists of one diesel driven EFW pump and one steam turbine driven EFW pump, each having a nominal 100% capacity (Ref. 3). The turbine driven EFW pump receives steam from one main steam line per OTSG via connections upstream of the associated main steam isolation valve. An alternative source of steam is available from the fossil units, Crystal River Unit 1 and 2 (Ref. 1), but cannot be relied upon to consider the EFW train OPERABLE. The diverse motive power of the two trains enhances both system availability and reliability. In addition, a safety-grade motor driven EFW pump is available to provide defense-in-depth for the EFW system. Total flow from the motor-driven EFW pump must not exceed 770 gpm to assure long-term operability of the motor drive. The motor driven EFW pump has no Improved Technical Specification requirements and cannot be used to meet the LCO. The motor driven EFW pump is powered from the 4160 ES Bus 3A. This pump has no automatic starting capability but can be manually started if offsite power is available or adequate capacity is available on the 1A Emergency Diesel Generator. An electrical interlock prevents operation of both the motor driven and diesel driven EFW Pumps at the same time. All three EFW pumps tie into common discharge headers providing the capability to feed either or both of the OTSGs.

(continued)

BASES

BACKGROUND (continued)

The preferred water source for both EFW pump trains is the Seismic Class I, missile protected dedicated EFW tank. Backup supplies of emergency feedwater are provided by the condensate storage tank and the Fire Service Water Storage Tanks. The main condenser hotwell can also supply the turbine driven EFW pump and the defense-in-depth motor driven EFW pump.

The pumps and OTSGs are protected from excessively high flow induced problems by cavitating venturis (EF-62-FO, EF-63-FO, and EF-64-FO) in the pump discharge lines, designed to limit EFW flow to the steam generators regardless of steam generator pressure (Ref. 7). In addition, the interlock between the motor driven and diesel driven EFW pumps and administrative controls preclude excessively high flow to the OTSGs from concurrent operation of all three EFW pumps.

DC powered block and control valves are actuated to feed the appropriate steam generator by the Emergency Feedwater Initiation and Control (EFIC) System. The capacity of either EFW pump is sufficient to remove decay heat and cool the plant until the Reactor Coolant System (RCS) pressure and temperature are low enough to place the Decay Heat Removal (DHR) System in service or until core decay heat can be removed solely by ECCS.

(continued)

BASES

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(continued)

BASES

BACKGROUND (continued)

Automatic actuation of the EFW System occurs on the following:

1. Trip of both main feedwater pumps with reactor power greater than 20% or the NI/RPS not in shutdown bypass;

2. Low level in either OTSG;

3. Low pressure in either OTSG;

4. Trip of all four reactor coolant pumps;

5. High pressure injection (HPI) actuation on both Channel A and B Engineered Safeguards Actuation System (ESAS) channels; and

6. AMSAC actuation.

The EFIC is a "smart" system which will feed either or both OTSGs with indications of low levels, but will isolate EFW to a faulted steam generator having a significantly lower steam pressure than the other.

The EFW System is designed to ANSI B 31.1 ES Seismic Class I and in accordance with General Design Criteria 2, 4, 5, 19, 44, 45, and 46 (Ref. 3, 4).

APPLICABLE SAFETY ANALYSIS

The EFW System is sized to provide sufficient decay heat removal capability to cooldown the RCS to the temperature and pressure at which the DHR System can be placed in service or at which core decay heat can be removed solely by ECCS for any of the following events:

- loss of main feedwater (LMFW);
- LMFW with loss of offsite power;
- main feedwater line break;
- main steam line break; and
- small break loss of coolant accident (LOCA).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The EFW System is designed to remain functional following the maximum hypothetical earthquake. It will also remain functional following a single failure in addition to any of the above events. No single failure prevents EFW from being supplied to the intact OTSG nor allows EFW to be supplied to the faulted OTSG. Note that in most cases of a main feedwater break or a steam line break, the depressurization of the affected OTSG would cause the automatic initiation of EFW. However, there will be some small break sizes for which automatic detection will not be possible. For these small breaks, the operator will have sufficient time in which to take appropriate action to terminate the event (Ref. 1).

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

LCO

Two independent emergency feedwater pumps and their associated flow paths are required to be OPERABLE. The OPERABILITY of the EFW pumps requires that each be capable of developing its required discharge pressure and flow. Additionally, the OPERABILITY of the turbine driven pump requires that it be capable of being powered from an OPERABLE steam supply through ASV-5. ASV-204 was installed to improve EFW reliability and is not required for OPERABILITY.

The motive power for the turbine driven pump is steam supplied from either OTSG from a main steam header upstream of the main steam isolation valves so that their closure does not isolate the steam supply to the turbine. Both steam supply flow paths through MSV-55 and MSV-56 (Condition A) to the turbine driven pump are required to be OPERABLE. The OPERABILITY of the associated EFW flow paths requires all valves be in their correct positions or be capable of actuating to their correct positions on a valid actuation signal.

The diesel driven EFW pump has a starting air system consisting of a safety-related air receiver that is maintained pressurized by a non-safety-related air compressor. The requirements for the air receiver are covered by Specification 3.7.19. The air is delivered to the diesel engine through DC powered valves. The DC power is provided by the diesel driven EFW pump DC distribution system battery.

(continued)

BASES

LCO (continued)

Inoperability of the EFW System may result in inadequate decay heat removal following a transient or accident during which main feedwater is not available. The resulting RCS heatup and pressure increase can potentially result in significant loss of coolant through the pressurizer code safety valves or the PORV.

APPLICABILITY

In MODES 1, 2, and 3 the EFW System is required to be OPERABLE and to function in the event that main feedwater is lost. In addition, the EFW System is required to supply enough makeup water to replace the secondary side inventory lost as the plant cools to MODE 4 conditions.

In MODES 4, 5 and 6, the OTSG need not be used to cooldown the RCS. Therefore, the EFW System is not required to be OPERABLE in these MODES.

ACTIONS

A.1

With one of the two steam supplies to the turbine driven EFW pump inoperable, action must be taken to restore the steam supply to OPERABLE status within 7 days. Allowing 7 days in this Condition is reasonable, based on the redundant OPERABLE steam supply to the pump and the low probability of an event occurring that would require the inoperable steam supply to the turbine driven EFW pumps.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of Conditions to be entered during any continuous failure to meet this LCO. The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The 'AND' connector between 7 days and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

(continued)

BASES

ACTIONS (continued)

B.1

If one of the EFW trains is inoperable, action must be taken to restore the train to OPERABLE status within 72 hours. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the EFW System, time needed for repairs, and the low probability of a DBA occurring during this time period. This condition includes the loss of two steam supply lines to the turbine driven EFW pump.

The second Completion Time for Required Action B.1 established a limit on the maximum time allowed for any combination of Conditions to be entered during any continuous failure to meet this LCO. The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The 'AND' connector between 72 hours and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

C.1 and C.2

If Required Action A.1 or Required Action B.1 cannot be completed within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

With both EFW trains inoperable, the plant is in a seriously degraded condition with no safety related means for conducting a cooldown. In such a condition, plant operation should not be perturbed by a forced action, including a power change, that might result in a trip. For this reason, the Technical Specifications do not mandate a plant shutdown. Rather the ACTIONS allow the plant to dictate the most prudent course of action (including plant shutdown) for the situation. The seriousness of this condition requires that action be initiated immediately to restore at least one EFW train to OPERABLE status.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the EFW water, steam supply flow, diesel starting air and fuel oil paths provides assurance that the proper flow paths exist for EFW operation. This SR does not apply t valves that are locked, sealed, or otherwise secured in position, since those valves are verified to be in the correct position prior to locking, sealing, or securing. These valves include valves in the main flow paths and the first normally closed valve in a branch line. In lieu of the first normally closed valve in the branch line, credit may be taken for verifying valve position of another valve downstream, providing the isolation of the flow path is achieved. Verifying correct valve alignment of valves immediately downstream of an unsecured valve still assures isolation of the flow path. There are several exceptions for valve position verification due to the low potential for these types of valves to be mispositioned. The valve types which are not verified as part of this SR include vent or drain valves, relief valves, instrumentation valves, check valves, sample line valves. A valve that receives an actuation signal is allowed to be in a non-accident position provided the valve will automatically reposition within the proper stroke time. For a power operated valve to be considered "locked, sealed, or otherwise secured", the component must be electrically and physically restrained.

This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The 45 day frequency is based on engineering judgment and is consistent with the frequency established for SR 3.7.5.2. SR 3.7.5.2 requires extensive EFW valve manipulation in order to perform the pump flow rate verification, such that a flow path verification is necessary following each performance.

SR 3.7.5.2

This SR verifies that the EFW pumps develop sufficient discharge pressure to deliver the required flow at the full open pressure of the MSSVs. Because it is undesirable to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.5 (continued)

of EFW flow paths must be demonstrated before sufficient core heat is generated that would require the operation of the EFW System during a subsequent shutdown. The Frequency is reasonable, based on engineering judgment, in view of other administrative controls to ensure that the flow paths are OPERABLE. To further ensure EFW System alignment, flow path OPERABILITY is verified, following extended outages to determine no misalignment of valves has occurred. This SR ensures that the flow path from the EFW tank to the OTSGs is properly aligned. This requirement is based upon the recommendation of NUREG 0737. The Frequency was modified slightly during ITS development (prior to entering MODE 2) to provide an SR 3.0.4 type exception. As written, the SR allows the plant to achieve and maintain MODE 3 conditions in order to perform the verification.

SR 3.7.5.6

Verifying battery terminal voltage ensures the ability of the battery to perform the intended function. The voltage requirements are based on the nominal design voltage of the battery. The 7 day frequency is consistent with IEEE-450.

REFERENCES

1. Enhanced Design Basis Document for the Emergency Feedwater and Emergency Feedwater Initiation and Control System.

2. BAW-10043, "Overpressure Protection for B&W Reactors," dated May 1972.

3. FSAR, Section 10.5.

4. 10 CFR 50, Appendix A.

5. ASME, Boiler and Pressure Vessel Code, Section XI, Inservice Inspection, Subsection IWP.

6. Deleted.

7. FPC calculation 187-0008, Rev. 6.

B 3.7 PLANT SYSTEMS

B 3.7.6 Emergency Feedwater Tank (EFT-2)

BASES

BACKGROUND

The function of the emergency feedwater (EFW) tank is to provide a safety grade source of water for the removal of decay and sensible heat from the Reactor Coolant System (RCS) and reactor core following an event requiring EFW System operation. The EFW tank provides a gravity feed to the EFW pumps, which supply the driving head necessary to inject the water into the steam generators (OTSGs). Within the OTSGs, heat from the RCS is transferred to the secondary coolant, which boils and is subsequently discharged to the atmosphere via the main steam safety valves (MSSVs) or atmospheric dump valves. If the main steam isolation valves (MSIVs) are open, the preferred, non-safety grade means of decay heat removal is to discharge the generated steam to the main condenser via the turbine bypass valves. This has the advantage of conserving condensate while minimizing radioactivity releases to the environment.

The EFW tank provides the secondary coolant necessary for the Emergency Feedwater System to function to remove heat from the RCS during accident conditions. It is tornado hardened, Seismic Category I and, therefore, designed to withstand earthquakes (Ref. 1). Additionally, the tank is enclosed by a missile protected, seismically qualified concrete structure which provides not only tornado missile protection, but also protection from environmental effects such as wind and wave loads (Ref. 2). The EFW tank has an overall capacity of 184,000 gallons, and a minimum dedicated volume of 150,000 gallons of condensate quality water. Two other sources of condensate quality water are available to effect the removal of decay heat and sensible heat: the condenser hotwells (150,000 gallon combined surveillance capacity available to EFP-1 and EFP-2) and the condensate storage tank (120,000 gallon surveillance capacity). Fire Service Water Storage Tanks have a 600,000 gallon surveillance water capacity available for natural circulation cooldown.

APPLICABLE SAFETY ANALYSIS

The EFW System provides water to the OTSGs to remove decay heat and establish RCS natural circulation conditions following certain design basis events. Although the capacity of the EFW tank

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSIS

The SW System provides cooling for components essential for the mitigation of design basis accidents. An ESAS signal will start both emergency SW pumps (each pump is actually two pump assemblies driven by a single motor), transfer cooling of the containment fan assembly cooling coils and fan motors from the CI System to the SW System, and isolate various non-essential loads. The two emergency pumps (100 percent capacity each), in conjunction with the three heat exchangers required to be OPERABLE by this LCO, provide the necessary capability for cooling the motor-driven EFW pump, containment fan assembly cooling coils and fan motors, spent fuel pool, SW and Nuclear Services Seawater System pump motors, and other equipment which must function following an accident.

By supplying the containment fan assembly cooling coils and fan motors following a LOCA, the SW System and the Reactor Building Spray System act in conjunction to ensure the pressure and temperature in containment are maintained less than the design limits. The OPERABILITY of the Reactor Building Spray System is addressed by LCO 3.6.6.

The Nuclear Services Closed Cycle Cooling Water System satisfies Criterion 3 of the NRC Policy Statement.

LCOs

The requirement for OPERABILITY of both emergency SW pumps and three of four SW heat exchangers in MODES 1 through 4 provides sufficient capacity to ensure adequate post-accident heat removal, considering a worst case single active failure. Each emergency SW pump is powered from a separate 4160 V ES bus. Each of the two sets of emergency SW pumps is capable of supplying 100 percent of the required system flow. Each heat exchanger is rated at one-third the total required system flow, thus 3 are required to be OPERABLE for this LCO (Ref. 2).

APPLICABILITY

In MODES 1, 2, 3, and 4, the SW system is a normally operating system that must be capable of performing its post-accident safety functions, which include providing cooling water to components required for Reactor Coolant System (RCS) and containment heat removal, equipment essential to safely shutdown the plant, and equipment required for adequate spent fuel pool cooling.

(continued)

BASES

APPLICABILITY (continued)

Three of the four heat exchangers must be OPERABLE to accommodate the design system heat load requirements.

In MODES 5 and 6, the SW System is not required to be OPERABLE due to the limitations on RCS temperature and pressure in these MODES. Additionally, there are no other Technical Specification LCOs supported by SW which are applicable during these plant conditions.

ACTIONS

A.1

With one of the emergency SW pumps and/or one of the required heat exchangers inoperable, the heat removal capacity of the SW System is degraded. In this Condition, adequate cooling of the containment and ES equipment served by SW cannot be assured following an accident coincident with a worst-case single active failure. Therefore, action must be taken to restore the affected component(s) to OPERABLE status. The 72 hour Completion Time for restoring full SW System OPERABILITY is consistent with other ECCS Specifications for a loss of redundancy Condition and, has been shown to maintain a suitable limit on risk. As such, this Completion Time is based on engineering judgment and is consistent with industry-accepted practice.

B.1 and B.2

If the inoperable SW component(s) cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The 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 3.7.7.1

Verifying the correct alignment for manual, power operated, and automatic valves in the SW flow path provides assurance that the proper flow paths exist for SW operation. The isolation of the SW flow to individual components may render these components inoperable, but does not affect the operability of the SW system. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1 (continued)

These valves include valves in the main flow paths and the first normally closed valve in a branch line. In lieu of the first normally closed valve in the branch line, credit may be taken for verifying valve position of another valve downstream, providing the isolation of the flow path is achieved. Verifying correct valve alignment of valves immediately downstream of an unsecured valve still assures isolation of the flow path. There are several exceptions for valve position verification due to the low potential for these types of valves to be mispositioned. The valve types which are not verified as part of this SR include vent or drain valves, relief valves, instrumentation valves, check valves and sample line valves. A valve that receives an actuation signal is allowed to be in a non-accident position provided the valve will automatically reposition within the proper stroke time. For a power operated valve to be considered "locked, sealed, or otherwise secured," the component must be electrically and physically restrained. This surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in their correct position.

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

SR 3.7.7.2

This SR verifies proper automatic operation of the SW valves on an actual or simulated actuation signal. The SW System is a normally operating system that cannot be fully actuated as part of routine testing during at-power operation. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was considered acceptable from a reliability standpoint.

The SR is modified by a note indicating the SR is not applicable in the identified MODE. This is necessary in order to make the requirements for automatic system response consistent with those for the actuation instrumentation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.7.3

This SR verifies proper automatic operation of the SW emergency pumps on an actual or simulated actuation signal. The SW System is a normally operating system that cannot be fully actuated as part of routine testing during at-power operation. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was considered acceptable from a reliability standpoint.

The SR is modified by a note indicating the SR is not applicable in the identified MODE. This is necessary in order to make the requirements for automatic system response consistent with those for the actuation instrumentation.

REFERENCES

1. FSAR, Section 9.5.

2. Enhanced Design Basis Document for Nuclear Services Closed Cycle Cooling Water System.

3. FSAR, Section 9.3.

B 3.7 PLANT SYSTEMS

B 3.7.8 Decay Heat Closed Cycle Cooling Water System

BASES

BACKGROUND

The Decay Heat Closed Cycle Cooling Water (DC) System facilitates the removal of decay heat from the reactor core. The system also removes process and operating heat from safety related components associated with decay heat removal during normal plant cooldown and following a transient or accident. During plant cooldown below approximately 250°F the DC system provides core heat removal by transferring heat from the Decay Heat Removal (DHR) System to the Decay Heat Seawater System. The system is divided into two independent and redundant trains, each capable of supplying 100 percent of the required normal and post-accident cooling. Each train contains a pump, a surge tank pressurized with nitrogen for volume and pressure control, and a heat exchanger which removes heat from the DHR system and rejects it to the Decay Heat Seawater System.

The design and operation of the DC system, along with a list of the components served, can be found in FSAR Section 9.5.2.2 (Ref. 1). For normal operation the DC pumps are started manually. However, in an emergency both DC pumps start automatically upon receipt of an Engineered Safeguards Actuation System (ESAS). The DC system supports long-term reactor decay heat removal following a loss of coolant accident (LOCA) when the Emergency Core Cooling System (ECCS) is recirculating water from the RB sump to the reactor core through the DH heat exchanger. The DC System also supports post-accident containment cooling by supplying cooling water to the reactor building spray pump motor coolers and bearings. Other loads supplied by this system are the DHR (LPI) pumps and motors, DC and decay heat seawater pump motors and two of the three make-up and purification (HPI) pump motors. The DC System supplies cooling to these pump motor heat exchangers, lube oil coolers, gear lube oil coolers, bearings, or air handling units to prevent overheating of the associated components (Ref. 2).

As a closed system, the DC System also serves as an intermediate barrier to radioactivity releases to the environment from potential leaks in interfacing systems.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS

The DC system provides cooling for components essential to the mitigation of plant transients and accidents. An ESAS initiation signal will start both DC pumps. This ensures that the required cooling capacity is provided to the essential equipment following a steamline break, steam generator tube rupture, makeup system letdown line failure, or LOCA. The running pumps (100 percent capacity each), in conjunction with an associated DC heat exchanger, reject heat to the Decay Heat Seawater System to ensure the necessary cooling flow to components required for reactor decay heat removal. By cooling the RB spray pumps and pump motors following a LOCA or SLB, the DC system supports the RB Spray System by ensuring the pressure and temperature in containment are maintained within acceptable limits. The OPERABILITY of the RB Spray System is addressed in LCO 3.6.6, "Reactor Building Spray and Containment Cooling Systems".

During normal and post-accident cooldown operations, when RCS temperature and pressure are reduced to allow the alignment of the DHR System to the RCS, DC System operation facilitates core heat removal by transferring heat from the DHR System to the Decay Heat Seawater System.

The Decay Heat Closed Cycle Cooling Water System satisfies Criterion 3 of the NRC Policy Statement.

LCO

The requirement for two DC trains to be OPERABLE assures adequate normal and post-accident heat removal from the reactor core and essential components, considering a worst case single active failure. One of the OPERABILITY considerations regarding these independent and redundant trains is that each valve in the flow path be in the correct post-accident position. Additionally, each DC pump must be capable of being powered from its emergency power supply and be capable of automatically starting on an ESAS actuation.

(continued)

BASES

APPLICABILITY In MODES 1, 2, and 3, the DC System is not a normally operating system, but must be capable of performing its post-accident safety functions, which include providing cooling water to components required for RCS and containment heat removal. Two independent 100 percent capacity DC trains must be OPERABLE to accommodate the design system heat load requirements and satisfy reliability considerations assuming a single failure.

In MODE 4, although RCS temperature and pressure are reduced, there remains sufficient stored energy that the occurrence of an accident would necessitate the post-accident cooling functions of the DC System. When temperature and pressure have been reduced sufficiently to allow alignment of the DHR System to the RCS, the DC System is no longer required for post-accident component cooling, but must continue to provide cooling to the DHR heat exchangers. Therefore, two trains of the DC System must remain OPERABLE throughout MODE 4 to ensure emergency preparedness and/or decay heat removal, assuming a single active failure.

In MODES 5 and 6, the DC System is in operation performing its normal safety function of RCS decay heat removal. The various means of removing reactor decay heat in MODES 5 and 6 are addressed in LCO 3.4.6, "RCS Loops - MODE 5, Loops Filled"; LCO 3.4.7, "RCS Loops - MODE 5, Loops Not Filled"; LCO 3.9.4, "DHR and Coolant Circulation - High Water Level"; and LCO 3.9.5, "DHR and Coolant Circulation - Low Water Level". In other words, the OPERABILITY requirements for the DC System are determined by the systems it supports. Therefore, this LCO is not applicable in MODES 5 and 6.

ACTIONS A.1

Required Action A.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.5, "RCS Loops - MODE 4," be entered if an inoperable DC train results in an inoperable required DHR loop. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for an inoperability of a required DHR loop.

(continued)

BASES

ACTIONS

A.1 (continued)

With one DC train inoperable, action must be taken to restore the train to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE DC train is adequate to perform the heat removal function. The 72 hour Completion Time for restoring full DC System OPERABILITY is the same as that for the ECCS Systems, whose safety functions are supported by the DC System. This Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE train and the low probability of a DBA occurring during this period.

B.1 and B.2

If the inoperable DC train cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The 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 3.7.8.1

Verifying the correct alignment for manual and power operated valves in the DC flow path provides assurance that the proper flow paths exist for DC operation. The isolation of the DC flow to individual components may render those components inoperable, but does not affect the operability of the DC system. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing.

These valves include valves in the main flow paths and the first normally closed valve in a branch line. In lieu of the first normally closed valve in the branch line, credit may be taken for verifying valve position of another valve downstream, providing the isolation of the flow path is achieved. Verifying correct valve alignment of valves immediately downstream of an unsecured valve still assures isolation of the flow path.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1 (continued)

There are several exceptions for valve position verification due to the low potential for these types of valves to be mispositioned. The valve types which are not verified as part of this SR include vent or drain valves, relief valves, instrumentation valves, check valves, and sample line valves. A valve that receives an actuation signal is allowed to be in a non-accident position provided the valve will automatically reposition within the proper stroke time. For a power operated valve to be considered "locked, sealed, or otherwise secured," the component must be electrically and physically restrained. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in their correct position.

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

SR 3.7.8.2

This SR verifies proper automatic operation of the DC pumps on an actual or simulated actuation signal. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was considered acceptable from a reliability standpoint.

The SR is modified by a note indicating the SR is not applicable in the identified MODE. This is necessary in order to make the requirements for automatic system response consistent with those for the actuation instrumentation.

REFERENCES

1. FSAR, Section 9.5.2.2.

2. Enhanced Design Basis Document for Decay Heat Closed Cycle Cooling Water System.

B 3.7 PLANT SYSTEMS

B 3.7.9 Nuclear Services Seawater System

BASES

BACKGROUND

The Nuclear Services Seawater System serves as the heat sink for the Nuclear Services Closed Cycle Cooling Water (SW) System, removing process and operating heat from safety-related components during normal operation, transients and accidents. During normal operation, the normal duty (i.e., non-engineered safeguards (ES)) SW pump also provides cooling to essential and non-essential components. Additionally, the SW System provides cooling water to the spent fuel pool cooling heat exchangers during all operating conditions. The OPERABILITY of the SW System is governed by LCO 3.7.7, "Nuclear Services Closed Cycle Cooling Water System."

The Decay Heat Seawater System and the Nuclear Services Seawater System together comprise the RW System. The Decay Heat Seawater System supports the DC System to provide cooling to safety-related pumps and heat removal from the Reactor Coolant System (RCS) and are addressed in LCO 3.7.10.

The Nuclear Services Seawater System contains one normal duty pump and two emergency service pumps located inside two separate compartments of the nuclear services seawater sump pit. One compartment contains the normal service pump, the B train emergency pump, and a decay heat seawater pump. The other compartment contains the A train emergency pump and a decay heat seawater pump. A separate underground intake conduit for each compartment connects the associated pump suctions to the intake canal (Ref. 1). The system provides cooling water to the tube side of four heat exchangers removing heat from the SW System and subsequently rejecting it to the ultimate heat sink by way of the discharge canal. The normal duty nuclear services seawater pump is powered by a non-safety related power source and is designed to provide sufficient flow to ensure heat removal during normal operation. The two emergency nuclear services seawater pumps are each nominally 100 percent capacity, providing sufficient flow for the maximum heat load expected following an emergency. Each of the emergency pumps is powered from a separate 4160 volt (ES) bus.

(continued)

BASES

BACKGROUND (continued)

The Nuclear Services Seawater System is designed to seismic category I requirements, except for the standpipe drain line. The design and operation of the Nuclear Services Seawater System along with a list of components served by SW during normal and emergency conditions, can be found in FSAR Section 9.5 (Ref. 2). Following an Engineered Safeguards Actuation System (ESAS) actuation, SW System flow paths are realigned to provide a reliable source of cooling to essential safeguards equipment which may be supplied by non-safety cooling water systems during normal operations. To ensure these additional heat loads can be accommodated, both emergency pumps are started simultaneously by an ESAS signal to provide adequate cooling in the event of a single active failure which disables one emergency pump.

APPLICABLE SAFETY ANALYSES

The Nuclear Services Seawater System supports the SW System in providing cooling for components essential to the mitigation of plant transients and accidents. The system has two separate 100 percent capacity underground intake conduits, independent emergency pumps, and underground discharge conduits to allow for a single failure while still providing the required flow. An ESAS signal will start both emergency pumps. This ensures the required cooling capacity is provided to the SW System following a steam line break, steam generator tube rupture, makeup system letdown line failure, or loss of coolant accident.

The Nuclear Services Seawater System satisfies Criterion 3 of the NRC Policy Statement.

(continued)

BASES

LCO

The requirement for the OPERABILITY of the Nuclear Services Seawater System including two emergency nuclear services seawater pumps provides redundancy necessary to ensure the system will provide adequate post-accident heat removal in the event of a coincident single failure.

Emergency nuclear services seawater pump OPERABILITY requires that each be capable of being powered from separate OPERABLE emergency buses. OPERABILITY of the associated flow paths requires that each valve in the flow path must be aligned to permit sea water flow from the intake canal to the SW heat exchangers, and subsequently to the discharge canal. The OPERABILITY of the SW heat exchangers, required to ensure proper heat removal capability, is addressed in LCO 3.7.7, "Nuclear Services Closed Cycle Cooling Water System".

APPLICABILITY

In MODES 1 through 4 the SW and Nuclear Services Seawater Systems are normally operating systems which must be prepared to provide post-accident cooling for components required for RCS and containment heat removal, equipment essential in providing the capability to safely shutdown the plant, and equipment required for adequate spent fuel pool cooling. The Nuclear Services Seawater System must be capable of providing its post-accident cooling assuming a single active failure. Therefore, both emergency pumps are required to be OPERABLE during these MODES.

In MODES 5 and 6, the Nuclear Services Seawater System is not required to be OPERABLE due to the limitations on RCS temperature and pressure in these MODES. Additionally, there are no other Technical Specification LCOs supported by the system which are applicable during these plant conditions.

ACTIONS

A.1

With one of the Nuclear Services Seawater pumps inoperable, action must be taken to restore the pump to OPERABLE status within 72 hours. The 72 hour Completion Time for restoring full Nuclear Services Seawater System OPERABILITY is consistent with that for ECCS Systems, whose safety functions are supported by the system. This Completion Time is based on engineering judgement and is consistent with accepted industry-accepted practice.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the inoperable emergency nuclear services seawater pump cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The 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 3.7.9.1

Verifying the correct alignment for manual valves in the nuclear services seawater flow path provides assurance that the proper flow paths exist to support SW operation. The isolation of the seawater flow to individual components may render those components inoperable, but does not affect the operability of the Nuclear Services Seawater System. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing.

These valves include valves in the main flow paths and the first normally closed valve in a branch line. In lieu of the first normally closed valve in the branch line, credit may be taken for verifying valve position of another valve downstream, providing the isolation of the flow path is achieved. Verifying correct valve alignment of valves immediately downstream of an unsecured valve still assures isolation of the flow path. There are several exceptions for valve position verification due to the low potential for these types of valves to be mispositioned. The valve types which are not verified as part of this SR include vent or drain valves, relief valves, instrumentation valves, check valves and sample line valves. A valve that receives an actuation signal is allowed to be in a non-accident position provided the valve will automatically reposition within the proper stroke time. For a power operated valve to be considered "locked, sealed, or otherwise secured," the component must be electrically and physically restrained. This surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in their correct position.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.2

This SR verifies proper automatic operation of the emergency nuclear services seawater pumps on an actual or simulated actuation signal. The RW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

The SR is modified by a note indicating the SR is not applicable in the identified MODE. This is necessary in order to make the requirements for automatic system response consistent with those for the actuation instrumentation.

REFERENCES

1. Enhanced Design Basis Document for Nuclear Services and Decay Heat Seawater System.

2. FSAR, Section 9.5.

3. FSAR, Section 14.2.2.

4. Enhanced Design Basis Document for Nuclear Services Closed Cycle Cooling Water System.

B 3.7 PLANT SYSTEMS

B 3.7.10 Decay Heat Seawater System

BASES

BACKGROUND

The Decay Heat Seawater System serves as the heat sink for the Decay Heat Closed Cycle Cooling Water (DC) System, which facilitates the removal of decay heat from the reactor core and the removal of process and operating heat from safety related components associated with decay heat removal following a transient or accident. During plant cooldown below approximately 250°F, the Decay Heat Seawater System removes heat which has been rejected to the DC System by the Decay Heat Removal (DHR) System. The OPERABILITY of the DC System is governed by LCO 3.7.8, "Decay Heat Closed Cycle Cooling Water System."

All structures and components in the decay heat seawater pump suction path are shared by the Nuclear Services and Decay Heat Seawater Systems (RW). The two decay heat seawater pumps are located inside two separate compartments of the nuclear services seawater sump pit. One compartment contains the A train decay heat seawater pump and an emergency nuclear services seawater pump. The other compartment contains the B train decay heat seawater pump, an emergency nuclear services seawater pump, and the normal duty nuclear services seawater pump. The OPERABILITY of the nuclear services seawater pumps is addressed in LCO 3.7.9, "Nuclear Services Seawater System." A separate underground intake conduit for each compartment connects the associated pump suctions to the intake canal (Ref. 1). The system provides cooling water to the tube side of two heat exchangers removing heat from the DC System and subsequently rejecting it to the ultimate heat sink (the Gulf of Mexico) by way of the discharge canal. The two decay heat seawater pumps are nominally 100 percent capacity, each providing sufficient flow for the maximum heat load expected for normal cooldown or following an emergency. Each of the pumps is powered from a separate 4160 volt engineered safeguards (ES) bus.

The design and operation of the Decay Heat Seawater System along with a list of the components served by DC can be found in FSAR Section 9.5.2.2 (Ref. 2). Both decay heat seawater pumps are started simultaneously on an Engineered Safeguards Actuation System (ESAS) signal to provide adequate cooling in the event of a single failure which disables a decay heat seawater pump or train.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS

The Decay Heat Seawater System supports the DC System in providing cooling for components essential to the mitigation of plant transients and accidents. The system has two separate 100 percent capacity underground intake conduits, independent pumps, and underground discharge conduits to provide for a single failure while still providing required flow. An ESAS initiation signal will start both decay heat seawater pumps upon low Reactor Coolant System (RCS) pressure and/or high containment pressure. This ensures that the required cooling capacity is provided to the DC System for cooling of components required for reactor heat removal following a steam line break, steam generator tube rupture, makeup system letdown line failure, or loss of coolant accident.

During normal and post-accident cooldown operations, when RCS temperature and pressure are reduced to allow the alignment of the DHR System to the RCS, the Decay Heat Seawater System is placed in service to support decay heat removal.

The Decay Heat Seawater System satisfies Criterion 3 of the NRC Policy Statement.

LCOs

The requirement for OPERABILITY of both decay heat seawater trains provides redundancy necessary to ensure the system will provide adequate post-accident heat removal in the event of a coincident single failure.

(continued)

BASES

LCOs (continued)

The OPERABILITY of the decay heat seawater pumps requires that they each be capable of being powered from an OPERABLE emergency bus. Each valve in the flow path must be in its correct position for permitting sea water flow from the intake canal to the DC heat exchangers, and subsequently to the discharge canal. The OPERABILITY of the DC System, required to ensure proper heat removal capability, is addressed in LCO 3.7.8, "Decay Heat Closed Cycle Cooling Water System."

APPLICABILITY

In MODES 1, 2, and 3 the DC and Decay Heat Seawater Systems may not be operating, but must be prepared to perform post-accident safety functions, which include providing cooling water to components required for RCS and containment heat removal. The Decay Heat Seawater System must be capable of providing its post-accident cooling assuming a single failure. Therefore, both pumps are required to be OPERABLE during these MODES.

In MODE 4, although RCS temperature and pressure are reduced, there remains sufficient stored energy that the occurrence of an accident would necessitate the post-accident cooling functions of the DC and Decay Heat Seawater Systems. When temperature and pressure have been reduced sufficiently to allow alignment of the DHR System to the RCS, the Decay Heat Seawater System is no longer needed for post-accident component cooling, but must provide cooling to the DC heat exchangers for cooldown and holding operations. Therefore, two trains of the Decay Heat Seawater System must remain OPERABLE throughout MODE 4 to ensure emergency preparedness and/or decay heat removal, assuming a single failure.

In MODES 5 and 6 the DHR, DC, and Decay Heat Seawater Systems are in operation performing their normal safety function of RCS decay heat removal. The various means of removing reactor decay heat in MODES 5 and 6 are addressed in LCO 3.4.6, "RCS Loops - MODE 5, Loops Filled"; LCO 3.4-7, "RCS Loops - MODE 5, Loops Not Filled"; LCO 3.9.4, "DHR and Coolant Circulation - High Water Level"; and LCO 3.9.5, "DHR and Coolant Circulation - Low Water Level". In other words, the OPERABILITY requirements for the DC System are determined by the systems it supports. Therefore, this particular LCO is not applicable in MODES 5 and 6.

(continued)

BASES

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.5, "RCS Loops - MODE 4," should be entered if an inoperable decay heat seawater train results in an inoperable required DHR loop. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for an inoperability of a required DHR loop.

If one of the decay heat seawater trains is inoperable, action must be taken to restore the train to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE train is adequate to perform the heat removal function. The 72 hour Completion Time for restoring full Decay Heat Seawater System OPERABILITY is the same as that for the ECCS Systems, whose safety functions are supported by the Decay Heat Seawater System. This Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE train and the low probability of a DBA occurring during this period.

B.1 and B.2

If the inoperable decay heat seawater train cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5. within 36 hours. The 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 3.7.10.1

Verifying the correct alignment for manual valves in the Decay Heat Seawater System flow path provides assurance that the proper flow paths exist for DC operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing.

These valves include valves in the main flow paths and the first normally closed valve in a branch line. In lieu of the first normally closed valve in the branch line, credit may be taken for verifying valve position of another valve downstream, providing the isolation of the flow path is achieved. Verifying correct valve alignment of valves immediately downstream of an unsecured valve still assures isolation of the flow path.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1 (continued)

There are several exceptions for valve position verification due to the low potential for these types of valves to be mispositioned. The valve types which are not verified as part of this SR include vent or drain valves, relief valves, instrumentation valves, check valves and sample line valves. A valve that receives an actuation signal is allowed to be in a non-accident position provided the valve will automatically reposition within the proper stroke time. For a power operated valve to be considered "locked, sealed, or otherwise secured," the component must be electrically and physically restrained. This surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in their correct position.

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

SR 3.7.10.2

This SR verifies proper automatic operation of the decay heat seawater pumps on an actual or simulated actuation signal. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

The SR is modified by a note indicating the SR is not applicable in the identified MODE. This is necessary in order to make the requirements for automatic system response consistent with those for the actuation instrumentation.

REFERENCES

1. Enhanced Design Basis Document for Decay Heat Closed Cycle Cooling Water System.

2. FSAR, Section 9.5.2.2.

B 3.7 PLANT SYSTEM

B 3.7.11 Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The function of the ultimate heat sink (UHS) is to provide the source of water necessary to safely operate, shutdown, and cooldown the plant. The UHS supports dissipation of decay heat following either a normal reactor shutdown or an accident. This function is provided via the Nuclear Services Seawater and Decay Heat Seawater (RW) Systems (Ref. 1). The UHS at Crystal River Unit 3 (CR-3) consists of the Gulf of Mexico, connected to an intake structure by a man made intake canal.

The RW System has been shown to provide adequate post-accident cooling with a maximum UHS temperature of 95°F (Ref. 2). The nuclear services and decay heat RW subsystems are connected to the UHS via underground intake conduits that connect the intake canal to the suction of the sea water pumps. These pumps are located in two separate compartments comprising the sea water pump pit with a floor elevation of 61.0 feet (CR-3 plant datum).

To provide sufficient NPSH to the safety-related RW pumps at the flow rates necessary to reach and maintain the plant in a safe shutdown condition, a minimum intake canal water level of 73.7 feet (Ref. 3) must be maintained. Additionally, although not part of this LCO, CR-3 periodically surveys the intake canal to ensure dimensions, in conjunction with the minimum level, provide adequate volume to meet the assumptions of the analysis.

The CR-3 UHS design is consistent with the recommendations of Regulatory Guide 1.27 (Ref. 4), providing assurance that the plant can reach and be maintained in a safe shutdown condition for at least 30 days following an accident.

APPLICABLE SAFETY ANALYSIS

The UHS is required to support the removal of heat from the reactor core, plant buildings, and safety equipment by providing the heat sink to the RW Systems. Particularly required is the capability to provide sufficient heat removal capacity to these systems during their emergency modes of operation. An Engineered Safeguards Actuation System (ESAS) signal automatically starts both emergency

(continued)

BASES

REFERENCES

6. FSAR, Chapter 14.

7. "Nuclear Services Closed Cycle Cooling, Decay Heat Closed Cycle Cooling, Nuclear Services and Decay Heat Seawater Systems Thermal and Hydraulic Analysis", FPC Calculation M88-0048.

B 3.7 PLANT SYSTEMS

B 3.7.12 Control Room Emergency Ventilation System (CREVS)

BASES

BACKGROUND

The principal function of the Control Room Emergency Ventilation System (CREVS) is to provide an enclosed environment from which the plant can be operated following an uncontrolled release of radioactivity or toxic gas.

The CREVS consists of two trains with much of the non-safety related equipment common to both trains and with two independent, redundant components supplied for major items of safety related equipment (Ref. 1). The major equipment consists of the normal duty filter banks, the emergency filters, the normal duty and emergency duty supply fans, and the return fans. The normal duty filters consist of one bank of glass fiber roughing filters. The emergency filters consist of a roughing filter similar to the normal filters, high efficiency particulate air (HEPA) filters, and activated charcoal adsorbers for removal of gaseous activity (principally iodine). The rest of the system, consisting of supply and return ductwork, dampers, and instrumentation, is not designed with redundant components. However, redundant dampers are provided for isolation of the ventilation system from the surrounding environment.

The ventilation exhaust duct is continuously tested by radiation monitor RM-A5, which has a range of 10^1 to 10^6 counts per minute. The monitor is set to alarm and initiate the emergency recirculation mode of operation when the radiation level reaches approximately two times the background count rate.

The Control Complex Habitability Envelope (CCHE) is the space within the Control Complex served by CREVS. This includes Control Complex floor elevations from 108 through 180 feet and the stair enclosure from elevation 95 to 198 feet. The elements which compromise the CCHE are walls, doors, a roof, floors, floor drains, penetration seals, and ventilation isolation dampers. Together the CCHE and CREVS provide an enclosed environment from which the plant can be operated following an uncontrolled release of radioactivity or toxic gas.

(continued)

BASES

BACKGROUND (continued)

Design calculations determine the maximum allowed leakage into the CCHE below which control room operator dose and toxic gas concentrations remain within approved limits.

Integrated leak tests of the CCHE determine actual leakage. The difference between allowed and actual leakage is converted to an allowance for breach areas (in square inches) that may exist in the CCHE to accommodate normal operating and maintenance activities. Breaches in excess of the calculated area renders the CCHE incapable of performing its function, and therefore inoperable. Routine opening and closing of the CCHE doors for personnel passage and the movement of equipment is accounted for in the design calculations. A continuous leakage of 10 cubic feet per minute is assumed to account for this. Holding or blocking doors open for short periods of time does not constitute a breach of the CCHE as long as the doors could be closed upon notification of a radiological or toxic gas release. NOTE

CREVS has a normal operation mode and recirculation modes. During normal operation, the system provides filtered, conditioned air to the control complex, including the controlled access area (CA) on the 95 foot elevation. When switched to the recirculation mode, isolation dampers close isolating the discharge to the controlled access area and isolating the outside air intake. In this mode the system recirculates filtered air through the CCHE.

The control complex normal duty ventilation system is operated from the control room and runs continuously. During normal operation, the outside air intake damper is partially open, the atmospheric relief discharge damper is closed, the discharge to the CA is open, and the system return damper is throttled. This configuration allows a controlled amount of outside air to be admitted to the control complex. The design temperature maintained by the system is 75°F at a relative humidity of 50%.

(continued)

BASES

BACKGROUND (continued)

Three signals will cause the system to automatically switch to the recirculation modes of operation.

1. Engineered Safeguards Actuation System (ESAS) signal (high reactor building pressure).

2. High radiation signal from the return duct radiation monitor RM-A5.

3. Toxic gas signal (chlorine or sulfur dioxide)

The recirculation modes isolate the CCHE from outside air to ensure a habitable environment for the safe shutdown of the plant. In these modes of operation, the controlled access area is isolated from the CCHE.

Upon detection of ESAS or toxic gas signals, the system switches to the normal recirculation mode. In this mode, dampers for the outside air intake and the exhaust to the CA will automatically close, isolating the CCHE from outside air exchange, and the system return damper will open thus allowing air in the CCHE to be recirculated. Additionally, the CA fume hood exhaust fan, CA fume hood auxiliary supply fan, and CA exhaust fan are de-energized and their corresponding isolation dampers close. The return fan, normal filters, normal fan, and the cooling (or heating) coils remain in operation in a recirculating mode.

Upon detection of high radiation by RM-A5 the system switches to the emergency recirculation mode. In this mode, the dampers that isolate the CCHE from the surroundings will automatically close. The CA fume hood exhaust fan, CA fume hood auxiliary supply fan, CA exhaust fan, normal supply fan, and return fan are tripped and their corresponding isolation dampers close. Manual action is required to restart the return fan and place the emergency fans and filters in operation. The cooling (or heating) coils remain in operation.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS

During emergency operations the design basis of the CREVS and the CCHE is to provide radiation protection to the control room operators. The limiting accident which may threaten the habitability of the control room (i.e., accidents resulting in release of airborne radioactivity) is the postulated maximum hypothetical accident (MHA), which is assumed to occur while in MODE 1. The consequences of this event in MODE 1 envelope the results for MODES 2, 3, and 4, and results in the limiting radiological source term for the control room habitability evaluation (Ref. 2). A fuel handling accident (FHA) may also result in a challenge to control room habitability, and may occur in any MODE. However, due to the severity of the MHA and the MODES in which the postulated MHA can occur, the FHA is the limiting radiological accident in MODES 5 and 6 only. The CREVS and the CCHE ensures that the control room will remain habitable following all postulated design basis events, maintaining exposures to control room operators within the limits of GDC 19 of 10 CFR 50 Appendix A (Ref. 3).

The CREVS is not in the primary success path for any accident analysis. However, the Control Room Emergency Ventilation System meets Criterion 3 of the NRC Policy Statement since long term control room habitability is essential to mitigation of accidents resulting in atmospheric fission product release.

LCO

Two trains of the control room emergency ventilation system are required to be OPERABLE to ensure that at least one is available assuming a single failure disabling the other train. Failure to meet the LCO could result in the control room becoming uninhabitable in the unlikely event of an accident.

The required CREVS trains must be independent to the extent allowed by the design which provides redundant components for the major equipment as discussed in the BACKGROUND section of this bases. OPERABILITY of the CREVS requires the following as a minimum:

a. A Control Complex Emergency Duty Supply Fan is OPERABLE;

(continued)

BASES

LCO (continued)

b. A Control Complex Return Fan is OPERABLE;

c. HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration functions;

d. Ductwork and dampers are OPERABLE, and air circulation can be maintained; and

e. The CCHE is intact as discussed below.

The CCHE boundary including the integrity of the doors, walls, roof, floors, floor drains, penetration seals, and ventilation isolation dampers must be maintained within the assumptions of the design calculations. Breaches in the CCHE must be controlled to provide assurance that the CCHE remains capable of performing its function.

NOTE

If the total open breach area in the CCHE exceeds the limit determined in approved design analyses (Reference 2), currently 35.5 square inches, the CCHE is rendered inoperable and entry into LCO Condition B is required. The upper bound of the breach area for the LCO is the sum of the breach area limit plus one square foot (144 square inches). If the Required Action of LCO Condition B is not met within the respective Completion Time, then Condition C or D, as applicable, must be entered.

The ability to maintain temperature in the Control Complex is addressed in Technical Specification 3.7.18.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CREVS must be OPERABLE to ensure that the CCHE will remain habitable during and following a postulated accident. During movement of irradiated fuel assemblies, the CREVS must be OPERABLE to cope with a release due to a fuel handling accident.

(continued)

BASES

ACTIONS

A.1

With one CREVS train inoperable, action must be taken to restore the train to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CREVS train is adequate to perform the radiation protection function for control room personnel. However, the overall reliability is reduced because a failure in the OPERABLE CREVS train could result in loss of CREVS function. The 7 day Completion Time is based on the low probability of an accident occurring during this time period, and ability of the remaining train to provide the required capability.

B.1

With the CCHE inoperable due to breaches in excess of approved design calculations, but within the criteria stated, operation may continue for 7 days. Restoration of excess breaches is not limited to returning the opening to its pre-breached condition, but can also be accomplished using temporary sealing measures as described in plant procedures and/or work instructions.

Condition B will permit opening breaches in the CCHE to support maintenance and modification to the habitability envelope boundary. It also will establish an allowance for the discovery of breaches during routine operation, and provide the opportunity to repair the breach in a time frame consistent with the low safety significance of small breaches in the CCHE.

Condition B also provides an opportunity, following an unsuccessful CCHE leak rate test, to determine the cause for excessive leakage, correct it, and perform a re-test. Excessive leakage measured during an integrated leak test can be converted to an equivalent breach size in accordance with approved design calculations. If the calculated breach size is less than or equal to 179.5 square inches then operation may continue while locating the source of the leakage and performing a re-test.

NOTE

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

NOTE

In MODE 1, 2, 3, or 4, if the inoperable CREVS train cannot be restored to OPERABLE status, or breaches in the CCHE which exceed allowable limits cannot be closed within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

NOTE

D.1 and D.2

NOTE

During movement of irradiated fuel assemblies, if the inoperable CREVS train cannot be restored to OPERABLE status, or breaches in the CCHE which exceed allowable limits, cannot be closed within the associated Completion Time, the OPERABLE CREVS train must immediately be placed in the emergency recirculation mode. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure will be readily detected.

NOTE

An alternative to Required Action D.1 is to immediately suspend activities that could release radioactivity and require isolation of the CCHE. This places the plant in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

Required Action D.1 and D.2 are modified by a Note indicating to place the system in the emergency mode if automatic transfer to emergency mode is inoperable.

E.1

NOTE

If both CREVS trains are inoperable or breaches in the CCHE exceed the limits of Condition B in MODE 1, 2, 3, or 4, the CREVS may not be capable of performing the intended function and the plant is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES

ACTIONS (continued)

F.1

NOTE

During movement of irradiated fuel assemblies, when two CREVS trains are inoperable or breaches in the CCHE exceed the limits of Condition B, action must be taken immediately to suspend activities that could release radioactivity that could enter the CCHE. This places the plant in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

NOTE

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

Standby systems should be checked periodically to ensure that they function properly. Since the environment and normal operating conditions on this system are not severe, testing each train once every month adequately checks proper function of this system. Systems such as the CR-3 design without heaters need only be operated for ≥ 15 minutes to demonstrate the function of the system. The 31 day Frequency is based on the known reliability of the equipment and the two train redundancy available.

SR 3.7.12.2

This SR verifies that the required CREVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The CREVS filter tests are in accordance with Regulatory Guide 1.52, (Ref. 4) as described in the VFTP Program description (FSAR, Section 9.7.4). The VFTP includes testing HEPA filter performance, charcoal absorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal. Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.12.3

This SR verifies that each CREVS train actuates to place the control complex into the emergency recirculation mode on an actual or simulated actuation signal. The Frequency of 24 months is consistent with the typical fuel cycle length.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.12.4

This SR verifies the integrity of the CCHE and the assumed inleakage rates of potentially contaminated air. During the emergency mode of operation, the CCHE is designed to be a closed environment having limited air exchange with its surroundings. Performance of a periodic leak test verifies the continuing integrity of the CCHE. The Frequency of 24 months is consistent with the typical fuel cycle length.

NOTE

The design of the CCHE precludes performance of the commonly applied leak test characterized by pressurization to a nominal value and measurement of the make up air required to maintain pressurization. The test for CR-3 is performed by operating CREVS in the emergency recirculation mode with the Auxiliary Building Ventilation System operating to maintain a differential pressure between the CCHE and the Auxiliary Building. The Auxiliary Building will be at least 1/8 inch water gauge negative relative to the CCHE. Tracer gas will be used to determine the leakage rate. The acceptance criteria for the test is a leakage rate that would not result in control room personnel exceeding dose limits described in Reference 3 following the most limiting accident. A detailed description of the conditions for conduct of the test are provided in Reference 2.

REFERENCES

1. FSAR, Section 9.7.2.1.g.

2. CR-3 Control Room Habitability Report, dated July 30, 1998.

3. 10 CFR 50, Appendix A, GDC 19.

4. Regulatory Guide 1.52, Rev. 2, 1978.

B 3.7 PLANT SYSTEMS

B 3.7.13 Fuel Storage Pool Water

BASES

BACKGROUND

The water contained in the spent fuel pool provides a medium for removal of decay heat from the stored fuel elements, normally via the spent fuel cooling system. In the event fuel pool cooling is lost when the pool is 140°F, assuming a full core is discharged under the conditions of Reference 1, the pool volume provides approximately 8 hours before boiling would occur (Ref. 1). The spent fuel pool water also provides shielding to reduce the general area radiation dose during both spent fuel handling and storage.

Although maintaining adequate spent fuel pool water level is essential to both decay heat removal and shielding effectiveness, the Technical Specification minimum water level limit is based upon maintaining the pool's iodine retention effectiveness consistent with that assumed in the evaluation of a fuel handling accident (FHA). The fuel handling accident described in FSAR Section 14.2.2.3 (Ref. 2), assumes that a minimum of 23 feet of water is maintained above the stored fuel. This assumption allows the use of the pool iodine decontamination factor used in the associated offsite dose calculation.

APPLICABLE SAFETY ANALYSES

The minimum water level in the fuel storage pool meets the assumptions of the FHA described in FSAR Section 14.2.2.3. The resultant 2 hour thyroid dose to a person at the exclusion area boundary and the 30 day dose at the low population zone are much less than 10 CFR 100 (Ref. 4) limits.

Although the water level above a damaged assembly lying on top of the fuel storage racks may be less than 23 feet, an extrapolation of the iodine removal efficiency factors indicates that the iodine removal factor used in the dose calculations will still be conversative at water levels as low as 21 feet (Ref. 5). The 23 foot criteria above the fuel in the racks will ensure at least 21 feet above the damaged assembly.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Fuel storage pool water level satisfies Criterion 2 of the NRC Policy Statement.

LCO

The specified water level of 23 feet over the top of the irradiated fuel assemblies seated in the storage racks (156 ft plant datum) preserves the assumptions of the FHA analysis (Ref. 2). As such, it is the minimum level allowed during movement of fuel within the fuel storage pool.

APPLICABILITY

This LCO is only applicable during movement of irradiated fuel assemblies in the fuel storage pool. This is consistent with the safety analysis which assumes the FHA initiating event to be the drop of an irradiated fuel assembly. Control of heavy loads, i.e., damaging the fuel assembly as a result of dropping a heavy load onto it, is not addressed by the safety analysis or this Technical Specification. Plant procedures are relied upon to prevent the dropping of heavy loads onto spent fuel.

ACTIONS

A.1

With the fuel storage pool level less than the minimum required level, the movement of fuel assemblies in the fuel storage pool is immediately suspended. This effectively precludes the occurrence of a fuel handling accident.

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 MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, placing the reactor in a shutdown condition in the event of an inability to suspend movement of irradiated fuel assemblies does nothing to compensate for the Required Action not met. It is inappropriate to subject the plant to a shutdown transient in this condition. In MODES 5 and 6, LCO 3.0.3 is not applicable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

The water level in the fuel storage pool must be checked periodically. Since there is no mechanism for inadvertently lowering the level during normal operations (changes in level are procedurally controlled) and there is a low level alarm should pool level drop to approximately 24 feet above the stored fuel assemblies, a 7 day Frequency is sufficient to provide assurance of adequate water level. The Frequency is based on engineering judgment and industry-accepted practice. When refueling operations are taking place, the level in the fuel pool is at equilibrium with that in the refueling canal and in the reactor vessel. The level in the refueling canal is verified daily by the performance of SR 3.9.6.1.

REFERENCES

1. FSAR, Section 9.3.1.
2. FSAR, Section 14.2.2.3.
3. Deleted.
4. 10 CFR 100.
5. FPC Calculation F-00-0001.

B 3.7 PLANT SYSTEMS

B 3.7.14 Spent Fuel Pool Boron Concentration

BASES

BACKGROUND

As described in the Bases for LCO 3.7.15, "Spent Fuel Assembly Storage," fuel assemblies are stored in the high-density region of the spent fuel pool storage racks in accordance with criteria based on initial weight-percent enrichment and discharge burnup. Although the water in the spent fuel pool is normally borated to ≥ 2000 ppm, the criteria that limit the storage of a fuel assembly to specific rack locations (criticality analysis) are conservatively developed without taking credit for the boron in the pool water.

APPLICABLE SAFETY ANALYSIS

The acceptance criteria for the fuel storage pool criticality analyses is that a k_{eff} of < 0.95 must be maintained for all postulated events. The storage racks are capable of maintaining this k_{eff} with unborated pool water at a temperature yielding the highest reactivity (assuming the storage restrictions of LCO 3.7.15 are met). Most abnormal storage locations will not result in an increase in the k_{eff} of the racks. However, it is possible to postulate events, such as the mis-loading of an assembly with a burnup and enrichment combination outside the acceptable area in Figure 3.7.15-1 and 3.7.15-2, or dropping an assembly between the pool wall and the fuel racks, which could lead to an increase in reactivity. For such events, credit is taken for the presence of boron in the pool water since the NRC does not require the assumption of two unlikely, independent, concurrent events to ensure protection against a criticality accident (double contingency principle). The reduction in k_{eff} caused by the boron more than offsets the reactivity addition caused by credible accidents (Ref. 3).

The concentration of dissolved boron in the fuel storage pool satisfies Criterion 2 of the NRC Policy Statement.

LCO

The required concentration of dissolved boron in the fuel storage pool of ≥ 1925 ppm preserves the assumption used in the analyses of the potential accident scenarios described above. This concentration of dissolved boron is the minimum required concentration for fuel assembly storage and movement within the fuel storage pool.

(continued)

BASES

APPLICABILITY

This LCO is applicable whenever fuel assemblies are stored in the spent fuel pool, until a complete spent fuel pool verification has been performed following the last movement of fuel assemblies in the spent fuel pool. This LCO does not apply following the verification since the verification would confirm that there are no misloaded fuel assemblies. With no further fuel assembly movement in progress, there is no potential for a misloaded fuel assembly or a dropped fuel assembly and the reactivity of the racks alone is adequate to preserve assumptions of the criticality analysis.

ACTIONS

A.1, A.2.1, and A.2.2

When the concentration of boron in the fuel storage pool is less than required, immediate action must be taken to preclude the occurrence of an accident. This is most efficiently achieved by immediately suspending the movement of fuel assemblies within the pool. This Action does not preclude movement of a fuel assembly to a safe position.

Additionally, action must be initiated immediately to restore pool boron concentration to within the LCO limit or a pool verification performed. Either of these Actions will restore compliance with the LCO or demonstrate the need for the LCO does not currently exist.

The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, placing the reactor in a shutdown condition in the event of an inability to suspend movement of fuel assemblies does nothing to compensate for the Required action not met. It is therefore inappropriate to subject the plant to a shutdown transient in this condition. In MODES 5 and 6, LCO 3.0.3 is not applicable.

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1

This SR verifies that the concentration of boron in the fuel storage pool is within the required limit. This is accomplished by sampling representative samples of the pool.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1 (continued)

Operating experience has shown significant differences between boron measured near the top of the pool and that measured elsewhere. As long as this SR is met, the analyzed events are fully bounded. The 7 day Frequency is acceptable because no major replenishment of pool water is expected to take place over this period of time.

REFERENCES

1. Criticality Safety Analysis of the Crystal River Unit 3 Pool A Spent Fuel Storage Rack, S. E. Turner. Southern Science, SS-162.

2. Reanalysis of the Crystal River Pool B Spent Fuel Storage Racks with Boraflex Degradation, S. F. Turner, Holtec International, HI-982056, October 20, 1998.

3. NRC Safety Evaluation Report for Amendment 134 to CR-3 Operating License, dated April 16, 1991.

B 3.7 PLANT SYSTEMS

B 3.7.15 Spent Fuel Assembly Storage

BASES

BACKGROUND

This document describes the Bases for the Spent Fuel Assembly Storage which imposes storage requirements upon irradiated and unirradiated fuel assemblies stored in the fuel storage pools containing high density racks. The storage areas, which are part of the Spent Fuel System, governed by this Specification are:

a. Fuel storage pool "A" and
b. Fuel storage pool "B".

In general, the function of the storage racks is to support and protect new and spent fuel from the time it is placed in the storage area until it is shipped offsite.

Spent fuel is stored underwater in either fuel storage pool A or B. Only fuel pool A has the capability to store failed fuel in containers. Spent fuel pool A features high density poison storage racks with a 10 1/2 inch center-to-center distance capable of storing 542 assemblies. Fuel pool A is capable of storing fuel with enrichments up to 5.0 weight percent U-235 (Ref. 1) without exceeding the criticality criteria of Reference 3 providing the fuel has sufficient burnup.

Spent fuel pool B also contains high density racks separated into 2 regions. The racks in Region 1 have a 10.60 inch center-to-center spacing capable of storing 174 assemblies. The high density racks in Region 2 have 9.17 inch center-to-center distance capable of storing 641 assemblies. Fuel pool B is capable of storing fuel with enrichments up to 5.0 weight percent U-235 (Ref. 2) without exceeding the criticality criteria of Reference 3, providing the fuel has sufficient burnup and required storage configuration.

It should be noted that the maximum enrichment limits are actually nominal values. The tolerance of fuel supplied by DOE is ± 0.013 weight percent. Thus, it is possible to have fuel with an initial enrichment slightly in excess of the stated limit. This is accounted for in the criticality analysis and is therefore acceptable.

(continued)

BASES (continued)

APPLICABILITY

In general, limiting fuel enrichment of stored fuel prevents inadvertent criticality in the storage pools. Inadvertent criticality is dependent on whether fuel is stored in the pools and is completely independent of plant MODE.

Therefore, this LCO is applicable whenever any fuel assembly is stored in high density fuel storage locations.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating LCO 3.0.3 does not apply. Since the design basis accident of concern in this Specification is an inadvertent criticality, and since the possibility or consequences of this event are independent of plant MODE, there is no reason to shutdown the plant if the LCO or Required Actions cannot be met.

When the configuration of fuel assemblies stored in the spent fuel pool is not in accordance with Figure 3.7.15-1, Figure 3.7.15-2, Figure 3.7.15-3, or the FSAR, immediate action must be taken to make the necessary fuel assembly movement(s) to bring the configuration into compliance. The Immediate Completion Time underscores the necessity of restoring spent fuel pool irradiated fuel loading to within the initial assumptions of the criticality analysis.

The ACTIONS do not specify a time limit for completing movement of the affected fuel assemblies to their correct location. This is not meant to allow an unnecessary delay in resolution, but is a reflection of the fact that the complexity of the corrective actions is unknown.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1

Verification by administrative means that initial enrichment and burnup of fuel assemblies in accordance with Figure 3.7.15-1 and Figure 3.7.15-2, and Figure 3.7.15-3 is required prior to storage of spent fuel in storage pool A or pool B (as applicable). This surveillance ensures that fuel enrichment limits, as specified in the criticality safety analysis (Ref. 2), are not exceeded. The surveillance Frequency (prior to storage in high density region of the fuel storage pool) is appropriate since the initial fuel enrichment and burnup cannot change after removal from the core.

REFERENCES

1. Criticality Safety Evaluation of the Pool A Spent Fuel Storage Racks in Crystal River Unit 3 with Fuel of 5.0% Enrichment, S. E. Turner, Holtec Report HI 931111, December 1993.

2. Reanalysis of the Crystal River Pool B Spent Fuel Storage Racks With Boraflex Degradation, S. F. Turner, Holtec International, HI-982056, October 20, 1998.

3. NUREG 0800, Standard Review Plan, Section 9.1.1 and 9.1.2, Rev. 2, July 1981.

4. 10 CFR 100.

5. CR-3 FSAR, Section 9.6.

B 3.7 PLANT SYSTEMS

B 3.7.16 Secondary Specific Activity

BASES

BACKGROUND

Under normal operating conditions, minimal quantities of radioactive contaminants will be present in the secondary coolant due to steam generator tube or tube sheet leakage. Such leakage allows primary coolant activity to enter the steam and power conversion system, where it may be released to the atmosphere via condenser off-gas or Main Steam System leakage.

The secondary coolant is monitored and sampled to detect reactor coolant system leakage into the secondary coolant. Small amounts of leakage would be detected by this monitoring. An abnormally high specific activity is indicative of an increase in the RCS activity level or an increase in primary to secondary system leakage.

During normal operations, secondary activity must be monitored to ensure that the total annual quantity of radioactive iodine released to the atmosphere is within the requirements of 10 CFR 50, Appendix I (Ref. 1). In addition to releases of secondary coolant activity which occur during normal operations, anticipated transients or accidents which result in main steam safety valve (MSSV) or atmospheric dump valves lifting or main steam line rupture will cause direct release of secondary activity to the atmosphere.

While it is important to maintain secondary coolant specific activity within the limit to assure the offsite dose calculations are bounding for all operating conditions, the analysis also provides an early indication of increasing primary to secondary system leakage.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS

The design basis transient and accident analyses presented in FSAR Chapter 14 which evaluate the offsite dose effects of secondary coolant release considered the initial secondary specific activity to be within the limit of this LCO. The acceptance criteria applied to the evaluation of accidental releases of radioactive material to the environment are given in terms of radiation dose received by a member of the general public at the exclusion area boundary for two hours immediately following the postulated release or at the low population zone boundary during the entire period of the radioactive cloud's passage (considered to be 30 days in Ref. 9). The limits established in 10 CFR 100 are a whole body dose of 25 Rem, or a 300 Rem total dose to the thyroid from iodine exposure.

With respect to offsite dose, the limiting accident involving release of secondary coolant activity is the main steam line break (SLB) postulated as a double-ended rupture of one main steam system line between the reactor building and turbine stop valves (Ref. 3 and 4). The SLB is assumed to result in the release of the activity contained in the steam generator inventory, the activity contained in the feedwater added to the steam generator prior to isolation, and the activity added to the steam generator due to RCS leakage during the cooldown period following the steam line break. The curies of secondary (steam generator and feedwater) activity released is small in comparison to that resulting from the postulated reactor coolant leakage following the SLB. The specific activity limit on secondary coolant helps ensure this small fraction compared to primary side releases.

A complete loss of AC power and steam generator tube rupture (SGTR) also result in offsite release of secondary coolant activity through the MSSVs and atmospheric dump valves. In the case of a complete loss of AC power, the quantity of secondary coolant released to the atmoshere could be greater than during a SLB. However, the overall offsite dose is considerably lower, since the primary to secondary leakage path will be isolated much earlier following an AC power loss than after a SLB (Ref. 6). The specific activity limit on secondary coolant helps ensure the dose from a loss of AC power will be bounded by a SLB accident.

In the case of a SGTR, the activity released from secondary side pre-break activity is insignificant compared to the activity released from the primary to secondary break flow.

(continued)

BASES (continued)

LCO

The specific activity of the secondary coolant system is required to be ≤ 4.5 E-4 microcuries per gram DOSE EQUIVALENT 1-131 (Ref. 7).

A secondary coolant system specific activity within this limit ensures that the offsite dose contribution of the secondary coolant activity does not exceed values considered in the safety analysis. Maintaining steam generator specific activity within this limit will ensure that the postulated post-accident whole body and thyroid doses will remain significantly less than the guideline values of 10 CFR 100 (Ref. 8).

APPLICABILITY

The limits for secondary coolant specific activity apply whenever the steam generators are required for RCS heat removal. During these conditions, the potential exists for radioactive releases to the environment via normal steam, condensate, and feedwater leakage, or as the result of a steam line failure.

In MODES 5 and 6, the steam generators are not required for RCS heat removal. Both the RCS and secondary coolant systems are depressurized, and the potential for primary to secondary leakage is minimal.

ACTIONS

A.1 and A.2

DOSE EQUIVALENT 1-131 exceeding the allowable value in the secondary coolant would result in unanalyzed offsite dose rates in the event of an accident. Thus, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The 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 3.7.16.1

This SR verifies that the secondary specific activity is within the limits of the accident analysis. A gamma isotopic analysis of the secondary coolant, which determines DOSE EQUIVALENT 1-131, confirms the validity of the safety

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.16.1 (continued)

analysis assumptions with respect to offsite releases. It also aids in the trending and identification of increasing isotopic concentrations that might indicate changes in reactor coolant LEAKAGE. The 31 day Frequency is based on the existence of other Surveillance Requirements to monitor activity and primary to secondary leakage rate and the existence of alarms and indications of these parameters in the control room.

REFERENCES

1. 10 CFR 50, Appendix I.
2. Deleted.
3. FSAR, Table 14-28.
4. FSAR, Section 14.2.2.
5. Deleted.
6. FSAR, Section 14.1.2.
7. FPC Fuels Calculation CMC-3, Revision 0, dated March 4, 1989.
8. 10 CFR 100.
9. TID-14844, Calculation of Distance Factors for Power and Test Reactor Sites, J. J. Dinunno, et al., March 23, 1962.

B 3.7 PLANT SYSTEMS

B 3.7.18 Control Complex Cooling System

BASES

BACKGROUND

The Control Complex Cooling System provides temperature control for the control room and other portions of the Control Complex containing safety related equipment.

The Control Complex Cooling System consists of two redundant chillers, associated chilled water pumps, and parallel duct mounted air heat exchangers that can receive chilled water from either chilled water pump. A train consists of a chiller and associated chilled water pump as well as a duct mounted heat exchanger that provide cooling of recirculated control complex air. The design of the Control Complex Cooling System contains features that allow either train chiller and associated chilled water pump to provide cooling capability to either duct mounted heat exchanger. Redundant chillers and chilled water pumps are provided for suitable temperature conditions in the control complex for operating personnel and safety related control equipment. The Control Complex Cooling System maintains the nominal temperature between 70°F and 80°F.

A single chiller and associated chilled water pump will provide the required heat removal for either duct mounted heat exchanger. The Control Complex Cooling System operation to maintain control complex temperature is discussed in the FSAR, Section 9.7 (Ref. 1).

APPLICABLE SAFETY ANALYSIS

The Control Complex Cooling System consists of redundant, safety related components, with some common piping. The Control Complex Cooling System maintains the temperature between 70°F and 80°F. A single active failure of a Control Complex Cooling System component does not impair the ability of the system to perform as designed. The Control Complex Cooling System is designed in accordance with Seismic Category I requirements. The Control Complex Cooling System is capable of removing heat loads from the control room and other portions of the Control Complex containing safety related equipment, including consideration of equipment heat loads and

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

personnel occupancy requirements, to ensure equipment OPERABILITY.

The Control Complex Cooling System satisfies Criterion 3 of the NRC Policy Statement.

LCO

Two redundant trains of the Control Complex Cooling System are required to be OPERABLE to ensure that at least one train is available, assuming a single failure disables one redundant component. A Control Complex Cooling train consists of a chiller and associated chilled water pump as well as a duct mounted heat exchanger that provides cooling of recirculated control complex air. All components of an OPERABLE train must be energized by the same train electrical bus. Total system failure could cause control complex equipment to exceed its operating temperature limits. In addition, the Control Complex Cooling System must be OPERABLE to the extent that air circulation can be maintained (See Specification 3.7.12).

APPLICABILITY

In MODES 1, 2, 3, and 4, the Control Complex Cooling System must be OPERABLE to ensure that the control complex temperature will not exceed equipment OPERABILITY requirements. During movement of irradiated fuel assemblies the Control Complex Cooling System must be OPERABLE to cope with a release due to a fuel handling accident.

ACTIONS

A.1

The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy and diversity of subsystems, the inoperability of one component in a train does not render the Control Complex Cooling System incapable of performing its safety function. Neither does the inoperability of two different components, each in a different train, necessarily result in a loss of function for the Control Complex Cooling System. The intent of this Condition is to maintain a combination of equipment such that the cooling capability equivalent to 100% of a single train remains available and in operation. This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable.

(continued)

BASES

ACTIONS

A.1 (continued)

With one or more components inoperable such that the cooling capability equivalent to a single OPERABLE train is not available, the facility is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be immediately entered.

With one or more Control Complex Cooling trains inoperable and at least 100% cooling capability of a single OPERABLE train available, the inoperable components must be restored to OPERABLE status within 7 days. In this Condition, the remaining Control Complex Cooling System equipment is adequate to maintain the control complex temperature. Adequate cooling capability exists when the control complex air temperature is maintained within the limits for the contained equipment and components. However, the overall reliability is reduced because additional failures could result in a loss of Control Complex Cooling System function. The 7 day Completion Time is based on the low probability of an event occurring requiring the Control Complex Cooling System and the consideration that the remaining components can provide the required capabilities.

B.1 and B.2

During movement of irradiated fuel, if the required Action and Completion Times of Condition A can not be met, the Control Complex Cooling System must be placed in operation immediately. This action ensures that the remaining Control Complex Cooling System components are available, and that any active failure will be readily detected.

An alternative to Required Action B.1 is to immediately suspend activities that could release radioactivity that might require the isolation of the control room. This places the plant in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

C.1 and C.2

In MODE 1, 2, 3, or 4, if the inoperable Control Complex Cooling System component cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner without challenging unit systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.18.1

Verifying that each Control Complex Cooling chiller's developed head at the flow test point is greater than or equal to the required developed head ensures that chiller's performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by Section XI of the ASME Code (Ref. 3). This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of the SR is in accordance with the Inservice Testing Program.

SR 3.7.18.2

This SR verifies that the heat removal capability of the system is sufficient to meet design requirements. This SR consists of a combination of testing and calculations. A 24 month Frequency is appropriate, as significant degradation of the system is slow and is not expected over this time period.

REFERENCES

1. FSAR, Section 9.7.

2. Deleted.

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

B.3.7 PLANT SYSTEMS

B 3.7.19 Diesel Driven EFW (DD-EFW) Pump Fuel Oil, Lube Oil and Starting Air

BASES

BACKGROUND

The DD-EFW Pump is provided with a dedicated fuel oil supply tank. The fuel oil capacity of this tank, which is located in a dedicated compartment in the DD-EFW Pump building, is sufficient for the pump to perform its intended function for a period of 7 days. The fuel oil supply capacity is calculated using 10 CFR 50 Appendix K assumptions to supply EFW flow to one or two steam generators for seven days and enough fuel capacity to cool the RCS to decay heat removal cut-in temperature. Margin for instrument error and fuel needed for normal surveillance is included in the fuel oil tank size calculation. This fuel oil capacity ensures adequate time is available to replenish the onsite supply from outside sources prior to the diesel engine running out of fuel.

Due to the proximity and location of the supply tank to the engine, the fuel oil is directly fed to the engine from the supply tank by the engine fuel pump. The fuel oil tank and piping are located inside the DD-EFW Pump building which is a seismic Class I building, which precludes consideration of the effects of missiles in their design.

For proper operation of the DD-EFW Pump, it is necessary to ensure the proper quality of the fuel oil. CR-3 has a Diesel Fuel Oil (DFO) Testing Program which is an overall effort to ensure the quality of the fuel oil. The program includes purchasing, on-site receipt acceptance testing of new fuel, offsite analysis of new fuel accepted, and periodic testing (both onsite and offsite) of the stored fuel oil. Additionally, the program includes water removal and biocide addition to control bacteriological growth. CR-3 is not committed to Regulatory Guide 1.137 or ANS 59.51 (ANSI N195), however, these standards were utilized as guidance in the development of the DFO Testing Program.

The DD-EFW Pump lube oil subsystem is designed to provide sufficient lubrication to permit proper operation of its associated diesel engine under all loading conditions. The system is required to circulate the lube oil to the diesel

(continued)

BASES

BACKGROUND (continued)

engine working surfaces and to remove excess heat generated by friction during operation. The lube oil inventory, including that contained in the engine sump, is sufficient to ensure 7 days of operation. This supply ensures adequate time is available to replenish lube oil from outside sources prior to the system running out of lube oil.

The DD-EFW Pump engine has an air start system with adequate capacity for six successive start attempts on the engine without recharging the air start receivers. A single DD-EFW pump engine start is assured with air receiver pressure > 150 psig.

APPLICABLE SAFETY ANALYSIS

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume Engineered Safeguard (ES) systems are OPERABLE. The DD-EFW Pump is designed to provide sufficient EFW flow capacity to ensure the availability of necessary emergency feedwater to one or two steam generators. The DD-EFW pump is part of the redundant and diverse EFW system that provide steam generator secondary side cooling water.

Since diesel fuel oil, lube oil, and the air start subsystem support the operation of the DD-EFW pump system, they satisfy Criterion 3 of the NRC Policy Statement.

LCO

A sufficient quantity of stored diesel fuel oil supply is required to be available to ensure the capability to operate the DD-EFW Pump for 7 days. Diesel fuel oil is also required to meet specific quality standards. This EFW train is one of the two, full capacity and diverse sources of emergency feedwater for steam generator secondary side cooling.

A sufficient lube oil supply must be available to ensure the capability to operate the diesel engine for its 7 day fuel capacity (without refueling) rating. Engine lube oil

(continued)

BASES

LCO (continued)

inventory supports the availability of the DD-EFW Pump to fulfill its mission of supplying EFW flow to one or both steam generators. The DD-EFW pump is required to provide emergency feedwater to one or two steam generators under the EFIC flow control scheme for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power.

The starting air system is required to have a minimum capacity for six successive engine start attempts without recharging the air start receivers. As such, the air start compressors are not addressed as a part of this (or any other) LCO.

APPLICABILITY

Emergency feedwater flow is required during a Small Break LOCA or loss of main feedwater in order to cool and depressurize one or both generators which supports the reactor shut down and maintains it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil, lube oil, and the starting air subsystem support DD-EFW Pump OPERABILITY, these features are required to be within limits whenever the DD-EFW pump is required to be OPERABLE.

ACTIONS

A.1

With total fuel oil volume in the supply tank < 9,480 gallons and > 8,335 gallons, there is enough fuel oil available to operate the DD-EFW pump for 6 days. However, the Condition is restricted to fuel oil level reductions, that maintain at least a combined 6 day supply. In this Condition, a period of 48 hours is allowed prior to declaring the associated DD-EFW Pump inoperable.

The 48 hour Completion Time allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of fuel oil to the tank. This period is acceptable based on the remaining capacity (> 6 days), the actions that will be initiated to obtain replenishment, and the low probability of an event occurring during this brief period.

(continued)

BASES

ACTIONS

B.1

With lube oil inventory between 211 and 221 gallons, there is not sufficient lube oil to support 7 days continuous operation of the DD-EFW Pump. However, the Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply. In this Condition, a period of 48 hours is considered adequate to restore the required volume prior to declaring the DD-EFW Pump inoperable. The volume specified includes the engine lube oil inventory contained in the sump. If the required volume cannot be restored, the DD-EFW Pump is declared inoperable.

The 48 hour Completion Time is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the actions that will be initiated to obtain replenishment, and the low probability of an event occurring during this brief period.

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion for DD-EFW Pump fuel oil particulates. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. However, poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean the fuel oil will not burn properly and given that proper engine performance has been recently demonstrated (per SR 3.7.5.2), it is prudent to allow a brief period of time prior to declaring the associated DD-EFW Pump inoperable. The 7 day Completion Time allows for further evaluation, resampling, and re-analysis of the DD-EFW Pump fuel oil.

(continued)

BASES

ACTIONS

D.1

With the new fuel oil properties defined in the Bases for SR 3.7.19.3 (fuel oil surveillance testing) not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties prior to declaring the associated DD-EFW Pump inoperable. 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, or to restore the stored fuel oil properties. This restoration may involve feed and bleed, filtering, or combinations of these procedures. Even if the DD-EFW Pump start and load was required during this time and the fuel oil properties were outside limits, there is a high likelihood that the DD-EFW Pump would still be capable of performing its intended function.

E.1

EFP-3 is equipped with two redundant banks of starting air receivers and associated components (air start motors, solenoid valves, etc.). Only one of these banks is required for operability.

With starting air receiver pressure < 177 psig, sufficient capacity for six successive DD-EFW Pump start attempts does not exist. However, as long as the receiver pressure is > 150 psig, there is adequate capacity for at least one start attempt, and the DD-EFW Pump 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 DD-EFW Pump inoperable. This period is acceptable based on the remaining air start capacity, the fact that most diesel engine starts are accomplished on the first attempt, and the low probability of an event occurring during this brief period.

F.1

With a Required Action and associated Completion Time not met, with fuel oil, lube oil, or starting air subsystems not within limits for reasons other than addressed by Conditions A through E, the DD-EFW Pump must be immediately declared inoperable. In this case, the ACTION for Specification 3.7.5, is entered.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.19.1

This SR provides verification that there is an adequate inventory of fuel oil in the supply tank to support operation of the DD-EFW pump for 7 days, assuming no offsite power and Appendix K decay heat removal EFW flow requirements. The 7 days is sufficient time to place the plant 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 the likelihood of any large reductions (use or leakage) of fuel oil during this period would be detected.

SR 3.7.19.2

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of operation of DD-EFW Pump assuming Appendix K decay heat removal EFW flow requirements. The 221 gallon requirement is based on the diesel manufacturer consumption values for the run time of the engine. The specified volume includes the lube oil contained in the sump.

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

SR 3.7.19.3

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 performance. 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.19.3 (continued)

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 D4057-88, (Ref. 6);

b. Verify in accordance with the tests specified in ASTM D975-74, (Ref. 7) that the sample has a maximum of 0.05% by volume water and sediment (using ASTM D2709-82, (Ref. 6), a Saybolt viscosity at 100°F of 32.6 SUS and 40.1 SUS, and a flash point of > 125°F;

c. Verify in accordance with the test specified in ASTM D287-82 (Ref. 6) that new fuel has an API specific gravity of 28 (min); and

d. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-91, (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 concern since the fuel oil is not added to the storage tank.

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 D975-74, (Ref. 7), are met for new fuel oil when tested in accordance with ASTM D975-74, (Ref. 7), except that a calculated Cetane Index, per ASTM D976 (Ref. 8) or D4737 (Ref. 9), is determined to estimate the actual Cetane Number. If the Cetane Index is not met, then a sample of fuel is tested in accordance with ASTM D613 (Ref. 10) to determine Cetane Number. The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DD-EFW Pump operation. This Surveillance ensures the availability of high quality fuel oil for the DD-EFW Pump diesel engine.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.19.3 (continued)

Fuel oil degradation during long-term storage is typically detected as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean 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 D2276-91, Method A (Ref. 6). This method involves a gravimetric determination of total particulate concentration in the fuel oil. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

The Frequency of this SR takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between tests.

SR 3.7.19.4

This Surveillance ensures that, without the aid of the re-fill compressor, sufficient air start capacity for the DD-EFW Pump diesel engine is available. The design requirements provide for a minimum of six engine start cycles without recharging. The pressure specified in this SR reflects the lowest value at which the six starts can be accomplished.

The 31 day Frequency takes into account the capacity, capability and other indications available in the control room for DD-EFW Pump start readiness, including alarms, to alert the operator to below normal air start pressure. In addition, the system design includes a feature to automatically start the air compressors on low air pressure.

(continued)

BASES

REFERENCES

1. FSAR, Section 10.5.

2. Regulatory Guide 1.137.

3. ANSI N195-1976, Appendix B.

4. FSAR, Chapter 6.

5. FSAR, Chapter 14.

6. ASTM Standards: D4057-88; D2709-82; D4176-91; D287-82; D2276-91, Method A.

7. ASTM Standard, D975-74, Table 1.

8. ASTM Standard, D976.

9. ASTM Standard, D4737.

10. ASTM Standard, D613.

BASES

ACTIONS

A.2 (continued)

If at any time during the existence of Condition A (one offsite circuit inoperable) both 'a' and 'b' above become met, this Completion Time begins to be tracked.

The remaining OPERABLE offsite circuit and EDGs are adequate to supply electrical power to Train A and Train B of the onsite Class 1E distribution system. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

According to the recommendations of Regulatory Guide 1.93 (Ref. 6), operation with one required offsite circuit inoperable should be limited to a period of time not to exceed 72 hours. In this condition, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. However, the remaining OPERABLE offsite circuit and EDGs are adequate to supply electrical power to the onsite Class 1E distribution system.

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

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failure to meet the LCO. If Condition A is entered while, for instance, an EDG is inoperable and that EDG is subsequently returned to OPERABLE status, LCO 3.8.1 may already have been not met for up to 72 hours. This could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the offsite circuit. At this time, an EDG could again become inoperable, the circuit restored to OPERABLE status, and an

(continued)

BASES

ACTIONS

A.3 (continued)

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.

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

B.1

To ensure a highly reliable power source in the event one EDG is inoperable, it is necessary to verify the availability of the OPERABLE offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met (Condition F). However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a EDG is inoperable, does not result in a complete loss of safety function of critical redundant required features. These features are designed with redundant safety related trains. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable EDG. Single train systems (from an electrical perspective), such as the turbine driven emergency feedwater pump, are not included.

(continued)

BASES

ACTIONS

B.2 (continued)

The Completion Time for Required Action B.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilties. 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 EDG is inoperable; and

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

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

Declaring the required features inoperable within four hours from the discovery of items 'a' and 'b' existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the plant to transients associated with shutdown.

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

(continued)

BASES

ACTIONS

B.3.1 and B.3.2

Required Action B.3.1 provides an option to testing the OPERABLE EDG in order to avoid unnecessary testing. If it can be determined that the cause of the inoperable EDG does not exist on the OPERABLE EDG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other EDG, the other EDG would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. If the common cause failure evaluation is indeterminate (the cause of the initial inoperable EDG cannot be confirmed not exist on the remaining EDG), performance of SR 3.8.1.2 is adequate to provide assurance of continued OPERABILITY of that EDG.

The Completion Time of 24 hours is reasonable to confirm that the OPERABLE EDG is not affected by the same problem as the inoperable EDG and is based on the recommendations of Generic Letter 84-15 (Ref. 7).

B.4

According to the recommendations of Regulatory Guide 1.93 (Ref. 6), operation with one EDG inoperable should be limited to a period not to exceed 72 hours.

In Condition B, the remaining OPERABLE EDG and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.4 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 failure to meet the LCO. Refer to the Bases for Required Action A.3 for additional information on this Completion Time.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

Required Action C.1, which applies when both required offsite circuits are inoperable, is intended to provide assurance that a DBA, coincident with a worst-case single failure, will not result in a complete loss of redundant required safety functions. The Completion Time for declaring the redundant required features inoperable is 12 hours; reduced from that allowed for one train 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 trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is no longer valid, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. Single train features (from an electrical perspective), such as the turbine driven emergency feedwater pump, are not included.

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 Condition C (two offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

According to the recommendations of Regulatory Guide 1.93 (Ref. 6), operation with two required offsite circuits inoperable should be limited to a period not to exceed 24 hours. In this condition, 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 EDGs inoperable. However, two factors tend to decrease the severity of this level of degradation:

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, the simultaneous loss of offsite AC sources coincident with a LOCA, and a worst-case single failure were postulated as a part of the original licensing basis. 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.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

If one required offsite source is restored within 24 hours, power operation may continue in accordance with the required Actions of Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the distribution system ACTIONS would not be entered if the de-energization of the busses was due to all AC sources to them being inoperable. Therefore, the Required Actions of Condition D are modified by a Note indicating that when Condition D is entered with no AC sources to one train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems-Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one EDG whether or not a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

According to the recommendations of Regulatory Guide 1.93 (Ref. 6), operation with one onsite and one offsite circuit inoperable should be limited to a period not to exceed 12 hours.

In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. However, since power system redundancy is provided by two diverse sources of power it may appear the reliability of the power systems in this Condition is higher than that in Condition C (loss of both required offsite circuits). This is not necessarily the case since 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 the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS

E.1

With the Train A and Train B EDGs inoperable, there are no qualified onsite standby AC sources. Thus, with an assumed loss of offsite electrical power, there would not be sufficient standby AC sources available to power the minimum required ES systems. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time is balanced with that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). However, since any inadvertent generator trip could also result in a total loss of offsite AC power, 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.

The 2 hour Completion Time is consistent with the recommendations of Reference 6.

F.1 and F.2

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 12 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power conditions in an orderly manner and without challenging plant systems.

G.1

Condition G corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any subsequent failures in the AC electrical power system will cause a loss of function condition, and potentially, a station blackout. Therefore, the unit is required to enter LCO 3.0.3 immediately and prepare for a controlled shutdown.

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SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function. This is consistent with 10 CFR 50, Appendix A, GDC 18 (Ref. 8). Periodic component tests are supplemented by extensive functional tests during outages (under simulated accident conditions). Where the SRs for this LCO specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 3933 V is 94.5% of the nominal 4160 V output voltage. This value allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is usually specified as 85% to 90% of name plate rating. The specified maximum steady state output voltage of 4400 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 EDG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3). Regulatory Guide 1.9 requirements are satisfied by monitoring EDG output.

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.1 (continued)

correct position to ensure that distribution buses and loads are connected or are capable of being 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 3.8.1.6

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the plant in a safe shutdown condition. To minimize wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note (Note 2 for SR 3.8.1.2) to indicate that all EDG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of SR 3.8.1.2 and SR 3.8.1.6 testing, the EDGs are started from standby conditions. Standby conditions for an EDG means that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with the manufacturer's recommendations.

SR 3.8.1.6 requires that, at a 184 day Frequency, the EDG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the FSAR, Chapter 14 (Ref. 5).

The 10 second start requirement is not applicable to SR 3.8.1.2 (see Note 3) when a modified start procedure is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.6 applies.

Since SR 3.8.1.6 requires a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This is the intent of Note 1 of SR 3.8.1.2.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.7 (continued)

24 month Frequency is based on engineering judgment, taking into consideration plant conditions needed to perform the Surveillance. Operating experience has shown the 24 month Frequency to be adequate. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.8.1.8

Each EDG 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 EDG 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. For the CR-3 EDGs, the largest single load is less than 750 kW. The surveillance test will have a minimum rejected load of 750 kW. According to Regulatory Guide 1.9 (Ref. 3), 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 CR-3, the acceptance criteria of ≤ 66.75 Hz is based on 75% of the difference between synchronous speed and an overspeed trip setpoint 15% above synchronous speed. Surveillance procedure acceptance criteria for this surveillance requirement may be lower than 66.75 Hz for a lower overspeed trip setpoint provided the acceptance criteria is still based on 75% of the difference between synchronous speed and the minimum overspeed trip setpoint. 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 for voltage is equal to 60% the 5 second load sequence interval associated with sequencing of the largest load. Four seconds for frequency is likewise based on Regulatory Guide 1.9 recommendations. SR 3.8.1.8.a corresponds to the maximum frequency excursion, while SR 3.8.1.8.b and SR 3.8.1.8.c are Regulatory Guide 1.9 specific voltage and frequency values to which the system must recover to following load rejection. Regulatory Guide 1.9 specifies nominal voltage and frequency values which are 4160V and 60 Hz respectively. The 24 month Frequency takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with expected fuel cycle lengths.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

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

This SR is modified by two Notes. The reason for Note 1 is that during power operation, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, safety systems. However, the Note recognizes that should an unplanned event occur in MODES 1 or 2, following verification that the acceptance criteria of the SR are met, the event can be credited as a successful performance of this SR. Note 2 acknowledges this SR may be performed using component loads or it may be performed by paralleling the EDG with offsite power. When the SR is performed with the EDG carrying the 4160 Volt ES bus, the power factor of the EDG is a function of the reactive component of the loads powered from it, and as such, is not under direct control of the operator.

SR 3.8.1.9

Per the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(2), each EDG is required to demonstrate proper operation for the DBA loading sequence to ensure that voltage and frequency are maintained within the required limits. Under accident conditions prior to connecting the EDGs to their respective buses, all loads are shed except load block 1 feeder breakers that power Class 1E loads (referred to as "permanently connected" loads). Upon reaching the required voltage and frequency, the EDGs are auto-connected to their respective 4160 V buses. Loads are then sequentially connected to the bus by the automatic load sequencing relays The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the EDGs due to high motor starting currents.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. However, the Note acknowledges that credit may be taken for unplanned events that satisfy this SR.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3, July 1993.
4. FSAR, Chapter 6.
5. FSAR, Chapter 14.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. Generic Letter 84-15.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, Rev. 1, August 1977.
10. Regulatory Guide 1.137, Rev. 1, October 1979.
11. ANSI C84.1-1982.
12. ASME, Boiler and Pressure Vessel Code, Section XI.
13. Deleted.

B 3.8 ELECTRICAL POWER SYSTEMS

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

BASES

BACKGROUND

Each emergency diesel generator (EDG) is provided with a fuel oil storage tank. The combined fuel oil capacity of both storage tanks is sufficient to operate one diesel for a period of 7 days while the EDG is supplying the upper limit of its 200-hour rating (Ref. 1). The fuel oil supply is calculated using the assumption that one EDG is available to supply sufficient post accident loads. This onsite fuel oil capacity ensures adequate time is available to replenish the onsite supply from outside sources prior to the diesel running out of fuel.

Fuel oil is transferred from the storage tank to the day tank by either of two transfer pumps associated with each EDG. The pumps and piping are redundant to preclude failure of one pump, or the rupture of any pipe, valve or tank resulting in the loss of more than one EDG. All outside tanks and piping are located underground to preclude consideration of the effects of missiles in their design.

For proper operation of the EDGs, it is necessary to ensure the proper quality of the fuel oil. CR-3 has a Diesel Fuel Oil (DFO) Testing Program which is an overall effort to ensure the quality of the fuel oil. The program includes purchasing, on-site receipt acceptance testing of new fuel, offsite analysis of new fuel accepted, and periodic testing (both onsite and offsite) of the stored fuel oil. Additionally, the program includes water removal and biocide addition to control bacteriological growth, and performance checks of the cathodic protection system for underground storage tanks. CR-3 is not committed to Regulatory Guide 1.137 or ANS 59.51 (ANSI N195), however, these standards were utilized as guidance in the development of the DFO Testing Program.

The EDG lube oil subsystem is designed to provide sufficient lubrication to permit proper operation of its associated EDG 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

(continued)

BASES

BACKGROUND (continued)

operation. The onsite lube oil storage, in addition to that contained in the engine sump, is sufficient to ensure 7 days of one EDG supplying the upper limit of its 200-hour rating. This supply ensures adequate time is available to replenish lube oil from outside sources prior to the EDG running out of lube oil.

Each EDG has an air start system with adequate capacity for six successive start attempts on the EDG without recharging the air start receivers. A single EDG start is assured with air receiver pressure ≥ 150 psig. Additional evaluations have been performed which indicate there is substantial margin included in the single start receiver pressure limit (Ref. 9).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume Engineered Safeguard (ES) systems are OPERABLE. The EDGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ES 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 the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of the NRC Policy Statement.

LCO

A sufficient combined stored diesel fuel oil supply is required to be available to ensure the capability to operate a single EDG at the upper limit of its 200-hour rating for 7 days. During an event that requires 7 days operation before replacement fuel oil is obtained, manual reconfiguration of loads and transferring the stored fuel oil supply from one tank to the other may be needed to support operation of the EDG. Diesel fuel oil is also required to meet specific quality standards.

(continued)

BASES

LCO (continued)

A sufficient lube oil supply must be available to ensure the capability to operate a single EDG at the upper limit of its 200-hour rating for 7 days. EDG lube oil sump level, in conjunction with the on-site supply and the ability to obtain replacement supplies within the required timeframe, supports the availability of EDGs 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. EDG 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."

The starting air system is required to have a minimum capacity for six successive EDG start attempts without recharging the air start receivers. As such, the air start compressors are not addressed as a part of this (or any other) LCO.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required in order 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 the starting air subsystem support EDG OPERABILITY, these features are required to be within limits whenever the associated EDG is required to be OPERABLE.

ACTIONS

The ACTIONS are modified by two Notes. Note 1 indicates separate Condition entry is allowed for each EDG. This is acceptable based upon the fact each EDG is treated as an independent entity for this Specification. Note 2 indicates LCO 3.0.4 is not applicable and MODE changes while in the ACTIONS of this Specification are permitted. It could be argued this Note is not required since this Specification allows indefinite operation. However, to avoid any future confusion on the allowance, LCO 3.0.4 has been specifically excepted. This is considered acceptable since operation in accordance with this Specification still means the EDG is OPERABLE.

(continued)

BASES

ACTIONS (continued)

A.1

With usable fuel oil volume in one or more storage tanks < 22,917 gallons, prompt action must be taken within 1 hour to verify that the combined fuel oil supply > 45,834 gallons. However, the Condition is restricted to fuel oil level reductions that maintain at least a combined 7 day supply. In this Condition, a period of 1 hour is allowed to ensure that sufficient fuel oil supply for 7 days of EDG operation at its upper 200-hour rating is available. In order to maintain the ability to treat the EDG as independent entities for the ACTIONS (from a fuel oil perspective), an artificial lower limit on stored fuel oil has been established. The minimum usable volume specified for each tank is equivalent to 3 days operation and was set to ensure a minimum combined 6 day supply.

The limit on combined supply recognizes that while one tank may contain less than 3.5 day supply, the usable volume in the other tank could be such that 7 day capacity still exists.

Consistent with the Bases for Surveillance 3.0.1, OPERABILITY is verified by ensuring the associated surveillance(s) has been satisfactorily completed within the required frequency and the equipment is not otherwise known to be inoperable.

B.1

With usable fuel oil volume in one or more storage tanks < 22,917 gallons and combined fuel oil supply < 45,834 gallons, sufficient fuel oil supply for 7 days of EDG operation at its upper 200-hour rating is not available. However, the Condition is restricted to fuel oil level reductions, that maintain at least a combined 6 day supply. In this Condition, a period of 48 hours is allowed prior to declaring the associated EDG inoperable. In order to maintain the ability to treat the EDG as independent entities for the ACTIONS (from a fuel oil perspective), an artificial lower limit on stored fuel oil has been established. The minimum usable volume specified for each tank is equivalent to 3 days operation and was set to ensure a minimum combined 6 day supply.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the inoperable DC electrical power subsystem cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power conditions in an orderly manner and without challenging plant systems. The 36 hour Completion Time for placing the plant in MODE 5 is also consistent with the recommendations of Regulatory Guide 1.93 (Ref. 8).

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while the battery is on float charge helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. A float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or a battery cell) in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the initial voltages assumed in the battery sizing calculations. The 7 day Frequency is consistent with manufacturer recommendations and IEEE-450 (Ref. 9).

SR 3.8.4.2

A visual inspection to detect corrosion of the battery cells and connections provides an indication of physical damage or abnormal deterioration that could potentially affect battery performance. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection. The removal of visible corrosion is a preventive maintenance activity. The presence of visible corrosion does not necessarily represent a failure of this SR provided visible corrosion is removed during performance of SR 3.8.4.2.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.2 (continued)

As an alternative to the visual inspection, the option is provided to measure connection resistance of each inter-cell, inter-rack, inter-tier, and terminal connection. This verification provides a more conclusive determination of battery OPERABILITY than provided by the visual. If the battery meets the acceptance criteria for connection resistance, it is OPERABLE, regardless of the amount of visible corrosion present at the terminals and connectors.

The acceptance criteria established for connection resistance are established based upon the ceiling value established by the manufacturer.

The connection resistance ceiling value for connections not involving cell to cell cable assemblies is required to be ≤ 25 mV. The connection resistance ceiling value for connections involving cell to cell cable assemblies is required to be ≤ 80 mV. This categorization forms the basis of the acceptance criteria established by the manufacturer. Overall battery internal resistance has been determined to acceptable as established by plant electrical calculations.

The 92 day Frequency for these inspections is considered acceptable based on operating experience related to detecting corrosion trends.

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The 18 month Frequency is based on engineering judgment, considering the desired plant conditions needed to perform the Surveillance. Operating experience has shown the SR is typically passed when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and resistance measurements of inter-cell, inter-rack, inter-tier, and terminal connections provide an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anticorrosion material is used to help ensure good electrical connections and to reduce terminal deterioration.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.4 and SR 3.8.4.5 (continued)

The connection resistance acceptance criteria of SR 3.8.4.5 are established based upon the ceiling value established by the manufacturer.

The connection resistance ceiling value for connections not involving cell to cell cable assemblies is required to be ≤ 25 mV. The connection resistance ceiling value for connections involving cell to cell cable assemblies is required to be ≤ 80 mV. This categorization forms the basis of the acceptance criteria established by the manufacturer. Overall battery internal resistance has been determined to acceptable as established by plant electrical calculations.

The 18 month Frequency of the Surveillance is based on engineering judgment, considering the desired plant conditions needed to perform the Surveillance. Operating experience has shown the SR is typically passed when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.8.4.6

This SR verifies that each battery charger be capable of supplying 190 amps and ≥ 125 V for ≥ 8 hours. These requirements are based on the design capacity of the chargers (Ref. 4) less some margin for testing. This allows the SR to verify, to the extent practical, the design current output of the charger without exceeding the design rating of 200 amps. According to Regulatory Guide 1.32 (Ref. 10), the battery charger supply capacity is based on the largest combined demands of the various steady state loads and the charging capacity needed to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the plant during these demand occurrences. The CR-3 1E battery charger sizing calculations indicate a current of approximately 100 amps is adequate to perform this function. Thus, the minimum required charging current and duration ensure that these requirements are satisfied, with substantial margin.

The Frequency is acceptable, considering the plant conditions needed to perform the test and the other administrative controls which ensure adequate charger performance during the 18 month interval.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.7

A battery service test is a special as-found test of the battery capability. It is performed to verify the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length correspond to the design duty cycle requirements specified in Reference 12.

The 24 month Frequency meets the intent of the recommendations of Regulatory Guide 1.32 (Ref. 10) and Regulatory Guide 1.129 (Ref. 11), which state that the battery service test should be performed during refueling operations, or at some other outage.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test once per 60 months.

A modified performance discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. The modified performance discharge test shall satisfy the requirements of both the service test and the performance test. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. However, Note 2 acknowledges that should an unplanned event occur in MODES 1, 2, 3, or 4, that following verification that the acceptance criteria of the SR are met, the event can be credited as a successful performance of this SR.

(continued)

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems-Operating

BASES

BACKGROUND

The onsite Class 1E AC, DC, and AC vital bus electrical power distribution systems are divided into two redundant and independent AC, DC, and AC vital bus electrical power distribution subsystems (trains).

The AC electrical power distribution subsystem for each train consists of a primary Engineered Safeguard (ES) 4160 V bus and secondary 480 and 120 V buses, distribution panels, motor control centers (MCCs) and load centers. Each 4160 V ES bus is fed from an offsite circuit as well as a dedicated onsite emergency diesel generator (EDG). During normal operation, each 4160 V ES bus is connected to a preferred offsite source. If all offsite sources are unavailable or not connected to a power supply, the EDG supplies power to the 4160 V ES bus. Control power for the 4160 V breakers is supplied from the Class 1E batteries. Additional description of these systems may be found in the Bases for LCO 3.8.1, "AC Sources-Operating," and the Bases for LCO 3.8.4, "DC Sources-Operating."

The secondary AC electrical power distribution system for each train includes the safety related load centers, MCCs, and distribution panels shown in Table B 3.8.9-1.

The 120 VAC vital buses are arranged in two load groups per train and are normally powered from the inverters. The alternate power supply for the vital buses are Class 1E constant voltage transformers (CVTs) powered from the same train as the associated inverter. Each constant voltage transformer is powered from a Class 1E AC bus. Operation of the inverters and CVTs is governed by LCO 3.8.7, "Inverters-Operating."

There are two independent 250/125 VDC electrical power distribution subsystems (one for each train).

The list of all required DC distribution buses is also presented in Table B 3.8.9-1.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in Chapter 6 (Ref. 1) and Chapter 14 (Ref. 2) of the FSAR assume two ES trains are OPERABLE. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ES systems so that the 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.

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution systems is consistent with the initial assumptions of the accident analyses and the design basis of the plant. This includes maintaining electrical power distribution systems OPERABLE during accident conditions in the event of:

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

b. A worst-case single failure.

The distribution systems satisfy Criterion 3 of the NRC Policy Statement.

LCO

The required power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and AC vital bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Two trains of AC, DC, and AC vital bus electrical power distribution subsystems are required to be OPERABLE in order to ensure that the redundancy incorporated into the ES systems design is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

(continued)

BASES

LCO (continued)

AC, DC, and AC vital bus electrical power distribution subsystems are considered OPERABLE when the associated buses, load centers, MCCs, and distribution panels are energized to their proper voltages.

In addition, tie breakers between 480 V ES bus 3A and 3B must be open. This prevents an electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem. If this were to occur, it could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the affected redundant electrical power distribution subsystems are no longer redundant and one train must be considered inoperable. This applies to the onsite, safety related redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4160 V buses from being powered from the same offsite circuit.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 5 and 6 are addressed in the Bases for LCO 3.8.10, "Distribution Systems-Shutdown."

ACTIONS

A.1

With one AC electrical power distribution subsystem inoperable, the remaining AC electrical power distribution subsystem in the other train is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. However, the overall reliability is reduced because a single failure in the remaining power distribution subsystems could result in the minimum required ES functions not being met. Therefore, the required AC buses, load centers, MCCs, and distribution panels must be restored to OPERABLE status within 8 hours.

(continued)

BASES

ACTIONS

A.1 (continued)

The most severe scenario addressed by Condition A is an entire train without AC power (i.e., no offsite power to the train and the associated EDG inoperable). In this condition, the plant has an increased vulnerability to a complete loss of AC power. It is, therefore, imperative that the operator's attention be focused on minimizing the potential for loss of power to the remaining train by stabilizing the plant, and on restoring power to the affected train. The 8 hour time limit for restoration, prior to requiring a plant shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train to the actions associated with shutting down the plant within this time limit; and

b. The low probability of an event occurring coincident with a single failure of a redundant component in the train with AC power.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failure to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently restored to OPERABLE status, LCO 3.8.9 may already have been not met for up to 2 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution restored to OPERABLE status. This could continue indefinitely.

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

(continued)

BASES

ACTIONS

B.1

With one AC vital bus inoperable, the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ES functions not being supported. Therefore, the AC vital bus must be restored to OPERABLE status within 8 hours.

Condition B represents a condition in which potentially both the DC source and the associated AC source are nonfunctional. In this situation the plant is significantly more vulnerable to a complete loss of all non-interruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining vital buses and restoring power to the affected vital bus.

The 8 hour limit is more conservative than Completion Times allowed for the vast majority of components that would be without adequate AC vital power. However, there are certain affected features Completion Times of shorter duration. The intent of the Improved Technical Specifications is to remain within this Specification only and not take the ACTIONS for inoperable supported systems. Taking this exception to LCO 3.0.2 for components without adequate vital AC power, that would have the Required Action Completion Times shorter than 8 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without adequate vital AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The low probability of an event occurring coincident with a single failure of a redundant component.

(continued)

BASES

ACTIONS

B.1 (continued)

The 8 hour Completion Time takes into account the importance of restoring the AC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

The third Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failure. Refer to the Bases for Required Action A.1 for further discussion of this Completion Time.

C.1

With DC bus(es) in DC electrical power distribution train inoperable, the remaining train is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution train could result in the minimum required ES functions not being met. Therefore, the DC buses must be restored to OPERABLE status within 2 hours.

Condition C represents a condition in which one train is without adequate DC power; potentially both with the battery significantly degraded and the associated charger inoperable. In this situation, the plant is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining trains and restoring power to the affected train.

The 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that would be without adequate AC vital power. However, there are certain affected features with Completion Times of shorter duration. The intent of the Improved Technical Specifications is to remain within this Specification only and not take the ACTIONS for inoperable supported systems. Taking this exception to LCO 3.0.2 for components without adequate vital AC power, that would have the Required Action Completion

(continued)

BASES

ACTIONS

C.1 (continued)

Times shorter than 2 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in plant conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

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

c. The low probability of an event occurring coincident with a single failure of a redundant component.

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

The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failure to meet the LCO. Refer to the Bases for Required Action A for further discussion of this Completion Time.

D.1 and D.2

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

(continued)

BASES

ACTIONS (continued)

E.1

Condition E corresponds to a level of degradation in which redundant safety-related trains have lost power to one or more busses. At this severely degraded level, the plant's ability to respond to an event may be significantly reduced. Therefore, if it is determined that redundant trains of a necessary function are concurrently inoperable, no additional time is justified for continued operation. The plant is required to immediately enter LCO 3.0.3 and begin preparations for a controlled shutdown.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

With no source range neutron flux monitor OPERABLE, actions to restore a monitor to OPERABLE status shall be initiated immediately. Once initiated, actions shall be continued until a source range neutron flux monitor is restored to OPERABLE status.

With no source range neutron flux monitor OPERABLE, there is no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions are suspended (in accordance with Required Actions A.1 and A.2), the core reactivity condition should remain relatively stable until two source range neutron flux monitors are restored to OPERABLE status. Additional confidence in the plant's stability during this condition is provided by performing SR 3.9.1.1 to ensure that the required boron concentration exists.

The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration and provides prompt confirmation the plant is operating in an acceptable condition. The subsequent Completion Time of once per 12 hours ensures that unplanned changes in boron concentration would be identified. The Completion Time is reasonable based on engineering judgment, considering the low probability of a change in core reactivity during this time period.

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

SR 3.9.2.1 is the performance of a CHANNEL CHECK. It is based on the assumption that the two indication channels should be consistent with each other given existing core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

The Frequency of 12 hours is based on engineering judgment and is consistent with the Frequency specified for the equivalent SR of the same instruments in LCO 3.3.9.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.2.2

SR 3.9.2.2 is the performance of a CHANNEL CALIBRATION every 24 months. The CHANNEL CALIBRATION for the source range nuclear instrumentation is a complete check and re-adjustment of the channels, from the count rate amplifier input to the indicators. The 24 month Frequency is based on the results of comprehensive instrument uncertainty calculations that accommodate 30 months of drift as approved in Amendment 152 (Ref. 3).

Performance of SR 3.3.9.2 meets the requirements of this Surveillance, and one performance may be used to satisfy both requirements.

There is a preamplifier in the instrumentation loop. However, there are no calibration adjustments possible on the preamplifier. The preamplifier has a fixed gain which is set by means of a physical link held in place by screws and which is therefore not subject to unintentional misadjustment. Proper functioning of the preamplifier is initially verified after it or the detector is replaced and is periodically verified by the routine surveillance CHANNEL CHECK required by SR 3.9.2.1. A malfunction or failure of the preamplifier will be apparent as a change in channel output and will result in preamplifier replacement.

This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. It is not necessary to test the detectors because generating a meaningful test signal is difficult. The detectors are of simple construction, and any failures in the detectors will be apparent as change in channel output.

REFERENCES

1. FSAR, Section 7.3.1.2.

2. FSAR, Section 14.1.2.4.

3. Amendment No. 152 to the CR-3 Technical Specifications, dated February 13, 1996.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Containment Penetrations

BASES

BACKGROUND

An accident which occurs during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment will have any released radioactivity limited from escaping to the environment. In MODE 6, the potential for containment pressurization as a result of an accident is not likely; therefore, the requirement to isolate the containment from the outside atmosphere is less stringent than those established for MODES 1 through 4. In order to make this distinction, the penetration requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that all potential escape paths for radioactivity are closed or capable of being closed.

The containment equipment hatch or outage equipment hatch (OEH) provides a means for moving large equipment and components into and out of containment. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, the equipment hatch or OEH must be held in place by at least four bolts. The required number of bolts is based on dead weight and is acceptable due to the low likelihood of a pressurization event. Good engineering practice dictates that the bolts required by this LCO be approximately equally spaced. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, containment closure is required; therefore, the door in the OEH (if installed) must always remain closed or be capable of being closed.

The containment air locks provide a means for personnel access during MODES 1, 2, 3, and 4 in accordance with LCO 3.6.2, "Containment Air Locks." Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. However, during periods of unit shutdown when containment OPERABILITY is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment ingress and egress is necessary. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, containment closure is required; therefore, the door interlock mechanism may remain disabled, but one air lock door must always remain closed or be capable of being closed.

(continued)

BASES

BACKGROUND (continued)

If the door in the OEH (if installed) or both doors in the containment air locks are open when containment closure is required, a designated individual must be readily available to close the door in the OEH and at least one door in each air lock. Operations personnel directly involved in refueling operations shall be aware of the identity of the designated individual(s). The designated individual(s) shall remain within sufficient proximity to the open doors to assist in evacuation of personnel inside containment and to close the open door(s) as soon as evacuation is completed.

The requirements on containment penetration closure ensure that a release of fission product radioactivity to the environment from the containment will be limited. The closure restrictions are sufficient to limit fission product radioactivity release from containment due to a fuel handling accident during refueling.

In MODE 6, it is necessary to periodically recirculate/exchange RB atmosphere in order to minimize radiation uptake during the conduct of refueling operations. The 48 inch purge valves are normally used for this purpose, but the mini-purge valves may be relied upon as well. Both valve types are automatically isolated on a unit vent-high radiation signal (from RMA-1). So long as one valve in the flow path is OPERABLE, these lines may remain unisolated during the subject plant conditions.

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated by a minimum of one isolation device. Isolation may be achieved by an automatic or manual isolation valve, blind flange, or equivalent. Equivalent isolation methods include use of a material (e.g., temporary sealant) that can provide a temporary, atmospheric pressure ventilation barrier for the other containment penetrations during fuel movements.

These penetrations may be open provided the total calculated flow rate out the open penetrations is less than or equal to the equivalent flow rate through a 48 inch containment purge line penetration. This allowance is consistent with the CR-3 fuel handling accident inside the reactor building. The licensing basis analysis assumed a puff release of radionuclides from the RB following the FHA event. No credit was taken for the RB purge filters. Limiting the flow rate out the open penetrations to a flow rate less than or equal to the flow rate through the RB purge system is reasonable and conservative, given the plant licensing basis. Offsite doses from this analysis were well within 10 CFR 100 limits. With the containment purge valves OPERABLE, no leakage value has to be assigned to these penetrations, and the entire

(continued)

BASES

BACKGROUND (continued)

50,000 cfm can be allocated to other penetrations providing direct access. With the containment purge valves inoperable, these valves are allowed to be open during the Applicability of this Specification, however; no additional penetrations are allowed to be un-isolated during this time.

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS or movement of fuel assemblies within containment with irradiated fuel in containment, the most severe radiological consequences result from a fuel handling accident. The fuel handling accident is a postulated event that involves damage to irradiated fuel (Ref. 1). Fuel handling accidents include dropping a single irradiated fuel assembly and handling tool or a heavy object onto other irradiated fuel assemblies. The requirements of LCO 3.9.6, "Refueling Canal Water Level," the administrative limit on minimum decay time of 72 hours prior to the movement of irradiated fuel in the vessel, and this LCO ensure that the release of fission product radioactivity subsequent to a fuel handling accident results in doses that are within the requirements specified in 10 CFR 100.

Containment penetrations satisfy Criterion 3 of the NRC Policy Statement.

LCO

This LCO limits the consequences of a fuel handling accident in containment by limiting the potential escape paths for fission product radioactivity from containment. The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed except for penetrations containing an OPERABLE purge or mini-purge valve. For the containment air locks and the OEH (if installed), both doors in the air locks and the door in the OEH may be open only under administrative controls. For the containment purge and mini-purge valves to be considered OPERABLE, these valves (penetrations) must be automatically isolable on a unit vent-high radiation isolation signal.

The definition of "direct access from the containment atmosphere to the outside atmosphere" is any path that would allow for transport of containment atmosphere to any atmosphere located outside the containment structure. This includes the Auxiliary Building. As a general rule, closed or pressurized systems do not constitute a direct path

(continued)

BASES

LCO (continued)

between the RB and outside environments. All permanent and temporary penetration closures should be evaluated to assess the possibility for a release path to the outside environment. For the purpose of determining what constitutes a "direct access" path, no failure mechanisms should be applied to create a scenario which results in a "direct access" path. For example, line breaks, valve failures, power losses or natural phenomenon should not be postulated as part of the evaluation process.

These penetrations may be open provided the total calculated flow rate out the open penetrations is less than or equal to the equivalent flow rate through a 48 inch containment purge line penetration.

APPLICABILITY

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

ACTIONS

A.1 and A.2

With the containment equipment hatch, OEH, air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere not in the required status, including failure to implement required administrative controls for open OEH and air lock doors and the containment purge or mini-purge valve penetrations not capable of automatic isolation when the penetrations are unisolated, the plant must be placed in a condition in which the isolation function is not

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

needed. This is accomplished by immediately suspending CORE ALTERATIONS and movement of irradiated fuel assemblies within containment. Performance of these actions shall not preclude moving a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

This Surveillance demonstrates that each of the containment penetrations required to be in its closed position is in that position, and that administrative controls required for open OEH and air lock doors are being implemented.

The Surveillance is performed every 7 days during CORE ALTERATIONS or movement of irradiated fuel assemblies within the containment. The Surveillance interval is selected to be commensurate with the normal duration of time to complete fuel handling operations.

SR 3.9.3.2

This Surveillance demonstrates that each containment purge and mini-purge valve actuates to its isolation position on an actual or simulated high radiation signal. The 24 month Frequency is consistent with other similar instrumentation and valve testing requirements. The Surveillance ensures that the valves are capable of closing after a postulated fuel handling accident to limit a release of fission product radioactivity from the containment. SR 3.6.3.5 demonstrates that the isolation time of each valve is in accordance with the Inservice Testing Program requirements.

REFERENCES

1. FSAR, Section 14.2.2.3.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Refueling Canal Water Level

BASES

BACKGROUND

The movement of irradiated fuel assemblies within containment or performance of CORE ALTERATIONS requires a minimum refueling canal water level of 156 ft plant datum. This maintains sufficient water level above the fuel contained in the vessel and the bottom of the fuel transfer canal, and the spent fuel pool to ensure iodine fission product activity is retained in the water to a level consistent with the dose analysis of a fuel handling accident (Ref. 1). Sufficient iodine activity would be retained to limit offsite doses from the accident to well within 10 CFR 100 limits (Ref. 3).

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS and movement of irradiated fuel assemblies, the water level in the refueling canal is an assumed initial condition in the analysis of the fuel handling accident in containment. This relates to the assumption that 99% of the total iodine released from the fuel is retained by the refueling canal water. There are postulated drop scenarios where there is < 23 ft above the top of the fuel bundle and the surface. In particular, this is the case for the period of time during which the assembly travels between the cavity and the deep end of the refueling canal. During this time, there is potentially 21 feet of water between the reactor vessel flange (135 ft plant datum) and the surface of the pool. The iodine retention factors used in the dose assessment are still conservative at water levels of 21 feet above the damaged fuel (Ref. 4). The 156 ft value was chosen to be consistent with the level specified for LCO 3.7.13, "Fuel Storage Pool Water Level" and plant configuration.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

The fuel handling accident analysis inside containment is described in Reference 1. With a minimum water level of 23 ft above the stored fuel, and the administrative limit on minimum decay time of 72 hours prior to movement of irradiated fuel in the vessel, analyses demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water such that offsite doses are maintained within allowable limits (Ref. 3).

Refueling canal water level satisfies Criterion 2 of the NRC Policy Statement.

LCO

A minimum refueling canal water level of 156 ft plant datum is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits. This minimum level also ensures an adequate operational window between the surface of the pool and the transfer winch for the RB fuel handling equipment.

APPLICABILITY

This Specification is applicable during CORE ALTERATIONS and when moving irradiated fuel assemblies within the containment. The LCO minimizes the potential of a fuel handling accident in containment which results in offsite doses greater than those calculated by the safety analysis. If irradiated fuel is not present in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Water level requirements for fuel handling accidents postulated to occur in the spent fuel pool are addressed by LCO 3.7.13, "Fuel Storage Pool Water Level."

ACTIONS

A.1, A.2 and A.3

With a refueling canal water level of < 156 ft plant datum, all CORE ALTERATIONS or movement of irradiated fuel assemblies shall be suspended immediately to preclude a fuel handling accident from occurring. The suspension of CORE ALTERATIONS and fuel movement shall not preclude completion of movement of a component to a safe position.

(continued)

BASES

ACTIONS

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

In addition to immediately suspending CORE ALTERATIONS or movement of irradiated fuel, actions to restore refueling canal water level must be initiated immediately. The immediate Completion Time is based on engineering judgment. When increasing refueling canal water level the boron concentration of the make-up and the effect of this concentration on the minimum specified in the COLR (Ref. LCO 3.9.1) must be considered.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum refueling canal water level of 156 ft plant datum ensures that the design basis for the postulated fuel handling accident analysis during refueling operations is met. Water at the required level above the top of the reactor vessel flange limits the consequences of damaged fuel rods that are assumed to result from a postulated fuel handling accident inside containment (Ref. 2).

The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls of valve positions, which make significant unplanned level changes unlikely.

REFERENCES

1. Deleted.

2. FSAR Section 14.2.2.3.

3. 10 CFR 100.

4. FPC Calculation F-00-0001.