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Ref: 10CFR50.90

CPSES-200600097
Log # TXX-06001
File # 00236

February 21, 2006

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

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES)
DOCKET NOS. 50-445 AND 50-446
LICENSE AMENDMENT REQUEST (LAR) 05-08
REVISION TO TECHNICAL SPECIFICATIONS 3.3.1, "REACTOR TRIP SYSTEM INSTRUMENTATION," 3.3.2, "ESFAS INSTRUMENTATION," 3.4.5, "RCS LOOPS – MODE 3," 3.4.6, "RCS LOOPS – MODE 4," AND 3.4.7, "RCS LOOPS – MODE 5, Loops Filled"

Dear Sir or Madam:

Pursuant to 10CFR50.90, TXU Generation Company LP (TXU Power) hereby requests an amendment to the CPSES Unit 1 Operating License (NPF-87) and CPSES Unit 2 Operating License (NPF-89) by incorporating the attached change into the CPSES Unit 1 and 2 Technical Specifications. This change request applies to both Units.

The proposed change will revise TS 3.3.1, 3.3.2, 3.4.5, 3.4.6, and 3.4.7 entitled Reactor Trip System Instrumentation," "ESFAS Instrumentation," "RCS Loops – Mode 3," "RCS Loops – Mode 4," and "RCS Loops – Mode 5, Loops Filled," respectively. License Amendment Request (LAR) 05-08 revises the Technical Specifications to reflect the different steam generator water level trip setpoints and steam generator inventory requirements associated with the planned replacement of the steam generators in Unit 1.

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Attachment 1 provides a detailed description of the proposed changes, a technical analysis of the proposed changes, TXU Power's determination that the proposed changes do not involve a significant hazard consideration, a regulatory analysis of the proposed changes and an environmental evaluation. Attachment 2 provides the affected Technical Specification (TS) pages marked-up to reflect the proposed changes. Attachment 3 provides proposed changes to the Technical Specification Bases for information only; these changes will be processed per CPSES site procedures. Attachment 4 provides retyped Technical Specification pages which incorporate the requested changes. Attachment 5 provides retyped Technical Specification Bases pages which incorporate the proposed changes.

TXU Power requests approval of the proposed License Amendment by February 15, 2007 (but not earlier than December 1, 2006), to be implemented within 120 days of the issuance of the license amendment. This approval date was selected to be consistent with the replacement of the Unit 1 steam generators during refueling outage 1RF12 scheduled for early 2007.

In accordance with 10CFR50.91(b), TXU Power is providing the State of Texas with a copy of this proposed amendment.

Should you have any questions, please contact Mr. Robert Kidwell at (254) 897-5310.

I state under penalty of perjury that the foregoing is true and correct.

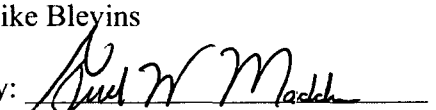
Executed on February 21, 2006.

Sincerely,

TXU Generation Company LP

By: TXU Generation Management Company LLC
Its General Partner

Mike Blevins

By: 
Fred W. Madden
Director, Regulatory Affairs

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Attachments
1. Description and Assessment
2. Proposed Technical Specifications Changes
3. Proposed Technical Specifications Bases Changes (for information)
4. Retyped Technical Specification Pages
5. Retyped Technical Specification Bases Pages (for information)

c - B. S. Mallett, Region IV
M. C. Thadani, Region IV
Resident Inspectors, CPSES

Ms. Alice Rogers
Environmental & Consumer Safety Section
Texas Department of State Health Services
1100 West 49th Street
Austin, Texas 78756-3189

ATTACHMENT 1 to TXX-06001

DESCRIPTION AND ASSESSMENT

LICENSEE'S EVALUATION

1.0 DESCRIPTION

By this letter, TXU Generation Company LP (TXU Power) requests an amendment to the CPSES Unit 1 Operating License (NPF-87) and CPSES Unit 2 Operating License (NPF-89) by incorporating the attached change into the CPSES Unit 1 and 2 Technical Specifications. Proposed change LAR 05-08 is a request to revise Technical Specifications (TS) 3.3.1, 3.3.2, 3.4.5, 3.4.6, and 3.4.7 entitled Reactor Trip System Instrumentation," "ESFAS Instrumentation," "RCS Loops – Mode 3," "RCS Loops – Mode 4," and "RCS Loops – Mode 5, Loops Filled," respectively, for Comanche Peak Steam Electric Station (CPSES) Units.

2.0 PROPOSED CHANGE

The proposed changes are required to reflect steam generator water level setpoints and inventory requirements appropriate for the Unit 1 replacement steam generators. The proposed changes would revise Technical Specification (TS) Table 3.3.1-1 and Table 3.3.2-1 to reflect the Steam Generator Water Level – Low-Low and Steam Generator Water Level – High-High trip setpoints appropriate for the Unit 1 replacement steam generators. The proposed change would also revise Surveillance Requirements (SR) 3.4.5.2, SR 3.4.6.2 and SR 3.4.7.2 and LCO 3.4.7.b to establish a steam generator water level sufficient to ensure the replacement steam generator tubes are covered and the required steam generators can effectively function as heat sinks. The Allowable Value for the Steam Generator Water Level – Low-Low reactor trip function setpoint would be set to 36% narrow range span, based on a Nominal Trip Setpoint of 38% narrow range span. The Allowable Value for the Steam Generator Water Level – High-High setpoint would be set to 86% narrow range span, based on a Nominal Trip Setpoint of 84% narrow range span. The water level required to ensure the steam generator tubes are covered during shutdown operating modes would be set to 38% narrow range span.

Attachment 2 contains mark-ups of the affected TS pages for the above proposed changes. Attachment 3 contains mark-ups of the affected TS Bases pages for information only.

3.0 BACKGROUND

The current steam generators in Unit 1 are the Westinghouse Model D4 design. The U-tubes were fabricated of Alloy 600 material and, based on plant and industry experience, are relatively susceptible to several corrosion mechanisms. These steam generators are scheduled to be replaced with Westinghouse Model Δ76 steam generators during the Unit 1 refueling outage 1RF12, currently scheduled to begin in early 2007.

The U-tube heat transfer area for the Δ76 design is increased over the D4 design by approximately 60% to 76,000 ft^3. The top of the U-tubes, approximately 8 ft higher than in the D4 design, is well above the bottom of the steam generator water level instrument span. In the D4 design, the top of the U-tubes is at approximately the same elevation as the bottom of the level instrument span. Thus, the steam generator water level indication corresponding to the top of the U-tubes is significantly greater in the Δ76 design.

Other License Amendment Requests have previously been submitted to address various aspects of the CPSES replacement steam generator program. Revised radiological dose consequences calculations, based on the methodologies presented in Regulatory Guide 1.195, and a proposed control room integrity Technical Specification were submitted for NRC review and approval via Reference 7.1. The radiological dose consequences of the postulated Chapter 15 accident analyses are based on thermal-hydraulic analyses performed for the Δ76 steam generator design at CPSES.

The methodologies to be used, on a cycle-specific basis, to perform the transient and accident analyses for the Δ76 steam generators have been submitted for NRC review and approval via Reference 7.2. The analyses supporting the setpoints described below were performed using these methodologies. Upon approval, these methodologies will be added to TS 5.6.5.b - the list of approved methodologies used to determine the core operating limit by LAR 05-06 (Reference 7.3).

The Nominal Trip Setpoints and Allowable Values for the steam generator water level – low-low and steam generator water level – high-high trip functions are based on the values for these parameters used in the safety analyses, plus appropriate allowances for instrument uncertainties. The safety analyses are identified in Chapters 6 and 15 of the Final Safety Analysis Report (FSAR) and were performed for the Δ76 steam generator design, using the methodologies submitted for NRC review via Reference 7.2. The Nominal Trip Setpoints and Allowable Values were determined using the NRC-approved setpoint methodology described in Reference 7.4.

4.0 TECHNICAL ANALYSIS

Steam Generator Water Level – Low-Low Trip Setpoints

The Steam Generator Water Level –Low-Low trip function provides protection for a loss of heat sink transient by initiating a reactor trip and initiating the Auxiliary Feedwater System. The Steam Generator Water Level –Low-Low trip function provides input to the Reactor Trip System (RTS) by initiating a reactor trip when the indicated water level falls below the setpoint. This same trip function also provides input to the Engineering Safety Features Actuation System (ESFAS), specifically the Auxiliary Feedwater System, when the indicated water level falls below the setpoint. A Steam Generator Water Level –Low-Low trip signal in any one steam generator will initiate a reactor trip signal and start the two motor-driven auxiliary feedwater pumps. A Steam Generator Water Level –Low-Low trip signal in two or more steam generators will also start the turbine-driven auxiliary feedwater pump.

The Steam Generator Water Level –Low-Low trip function is explicitly credited in the analyses of the Turbine Trip transient, the Loss of Non-emergency AC Power to the Station Auxiliaries transient, the Loss of Main Feedwater transient, and the Main Feedwater Line Break accident, all described in Section 15.2 of the FSAR. This trip function is also credited for selected break sizes in the development of mass and energy releases following a steam line break, as described in FSAR Section 6.2. In each of these analyses, the value chosen for use in the safety analyses (i.e., the Safety Analysis Limit) is 0% of the narrow range span. Those transients and accidents identified in FSAR Chapter 15 were analyzed with the Δ76 steam generator model and methods described in Reference 7.2. Due to the recirculation flow path within the steam generator, even though the Safety Analysis Limit is below the tops of the steam generator U-tubes, the tubes remained covered with water, and the steam generator remained an effective heat sink prior to the level falling below the assumed Steam Generator Water Level –Low-Low setpoint. The conclusions of each analysis were that the relevant event acceptance criteria were shown to be met. The continued validity of each of these analyses is addressed on a reload-specific basis.

Once the Safety Analysis Limits are established, instrument uncertainty analyses are performed to establish the Nominal Trip Setpoint, presented in TS Bases Tables B3.3.1-1 and B3.3.2-1, and the Allowable Value, presented in TS Tables 3.3.1-1 and 3.3.2-1. As described in the TS 3.3.1 and 3.3.2 Bases, the essential elements of the methodology are described in "Westinghouse Setpoint Methodology for Protection Systems Comanche Peak Unit 1, Revision 1," WCAP-12123, Revision 2, April, 1989 (Reference 7.4). Changes in accordance with this methodology have been reviewed by the Staff in the original Unit 1 Technical Specifications (Reference 7.5), the original Unit 2 Technical Specifications and in several subsequent license amendments (e.g., amendments 21/7 and 22/8 to the Unit 1/Unit 2 Technical Specifications). The methodology to derive the Trip Setpoints is based upon combining all of the uncertainties in the channels. The actual Nominal Trip Setpoint is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a Channel Operability Test. Trip setpoints consistent with the requirements of the Allowable Value ensure that design limits are not violated during transients and accidents. The Allowable

Value of Table 3.3.1-1 is the Limiting Safety System Setting. The Nominal Trip Setpoint is the value at which the bistable is set and is the expected value to be achieved during calibration. The trip setpoint value ensures the LSSS and the safety analysis limits are met for the time period of the surveillance interval when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the "as left" setpoint value is within the band for CHANNEL CALIBRATION uncertainty allowance (i.e., ± rack calibration + comparator setting uncertainties). The trip setpoint value of Tables B 3.3.1-1 and B 3.3.2-1 is therefore considered a "nominal" value (i.e., expressed as a value without inequalities)." The steam generator water level indication issues identified in Westinghouse Nuclear Safety Advisory Letter (NSAL) 02-3 and Revision 1, NSAL 02-4, and NSAL 02-5 have been addressed in the development of this setpoint.

Using this methodology and the Safety Analysis Limit of 0% narrow range span, the Nominal Trip Setpoint is established to be 38% narrow range span, and the corresponding Allowable Value is established as 36% narrow range span. These values are the same for both the Reactor Trip System function of TS 3.3.1 and the Engineered Safety Feature Actuation System function of TS 3.3.2 and corresponding Bases tables.

Steam Generator Water Level – High-High Trip Setpoints

The Steam Generator Water Level – High-High trip function is also designated as the P-14 signal. This signal initiates a turbine trip and feedwater isolation. The primary functions of the Turbine Trip and Feedwater Isolation signals are to prevent damage to the turbine due to water in the steam lines and to stop the excessive flow of feedwater into the steam generators. These functions are necessary to mitigate the effects of a high water level in the steam generators due to excessive feedwater flow, which could result in carryover of water into the steam lines and excessive cooldown of the primary system.

The Steam Generator Water Level –High-High trip function is credited in the analysis of the Increase in Feedwater Flow transient described in FSAR Section 15.1.2. This transient was analyzed with the Δ76 steam generator model and methods described in Reference 7.2. The value chosen for the trip setpoint for use in the safety analyses (i.e., the Safety Analysis Limit) is 100% of the narrow range span. The conclusion of the analysis was that the relevant event acceptance criteria were met. The continued applicability of this analysis is addressed on a reload specific basis.

As previously described for the Steam Generator Water Level – Low-Low trip function, once the Safety Analysis Limits are established, instrument uncertainty analyses are performed to establish the Nominal Trip Setpoint, presented in TS Bases Table B3.3.2-1, and the Allowable Value, presented in TS Table 3.3.2-1. The same uncertainty methodology was used for this trip function. The steam generator water level indication issues identified in Westinghouse Nuclear Safety Advisory Letter (NSAL) 02-3 and Revision 1, NSAL 02-4, and NSAL 02-5, have been addressed in the development of this setpoint.

Using this methodology and the Safety Analysis Limit of 100% narrow range span, the Nominal Trip Setpoint is established to be 84% narrow range span, and the corresponding Allowable Value is established as 86% narrow range span.

Steam Generator Water Level for Shutdown Conditions

In the shutdown operating modes (i.e., Mode 3, Mode 4, and Mode 5 with the RCS loops filled), one or more steam generators are required to be available, if required, for cooling the Reactor Coolant System with natural circulation. The primary function of the Reactor Coolant System in this mode of operation is the removal of decay heat and transfer of this heat either to the steam generator secondary side coolant via natural circulation or to the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal in Modes 4 and 5 with the RCS loops filled is via the RHR System, the steam generators are specified as a backup means for redundancy. To satisfy this capability, the required steam generator water inventory must be sufficient to completely cover the steam generator U-tubes to ensure the steam generator can function as an effective heat sink.

In the existing CPSES steam generators, the top of the U-tubes is at approximately the same elevation as the lower narrow range instrument tap (i.e., 0% narrow range span). However, in the Δ76 steam generator, the top of the U-tubes corresponds to approximately 31% narrow range span. The steam generator water level indication uncertainty for normal operation has been calculated to be approximately 6% span. Therefore, an indicated water level of 38% narrow range span has been selected as the water level required to ensure the Δ76 steam generators can function as an effective heat sink. Non-coincidentally, this value is consistent with the proposed Steam Generator Water Level –Low-Low trip function Nominal Trip Setpoint for Unit 1.

The current TS SR 3.4.5.2 is applicable in Mode 3 and requires verification of steam generator operability by ensuring that the secondary side narrow range water level is $\geq$ 10% for the required RCS loops. If the SG secondary side narrow range water level is $<$ 10%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat.

The current TS SR 3.4.6.2 is applicable in Mode 4 and requires verification of steam generator operability by ensuring that the secondary side narrow range water level is $\geq$ 10%.

The current TS 3.4.7.b and the associated SR 3.4.7.2 are applicable in MODE 5 with the RCS loops filled and again require verification of steam generator operability by ensuring that the secondary side narrow range water level is $\geq$ 10%.

In each of the four locations described above, the steam generator water level requirement will be revised to read "...$\geq$ 38% for Unit 1 and $\geq$ 10% for Unit 2."

Conforming Changes in accordance with draft TSTF-493

In anticipation of NRC approval of TSTF-493; "Revise LSSS Surveillance Requirements to Ensure Compliance with 10CFR50.36" (presently in a "final draft" version awaiting NRC approval) two footnotes are proposed to TS Table 3.3.1-1 and Table 3.3.2-1. These footnotes, applicable only to the Steam Generator Water Level – Low-Low and Steam Generator Water Level – High-High trip functions, incorporate requirements currently described in the CPSES Technical Specification Bases and lower-tier procedures into the CPSES Unit 1 and 2 Technical Specifications.

5.0 REGULATORY ANALYSIS

5.1 No Significant Hazards Consideration

TXU Power has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10CFR50.92, "Issuance of amendment," as discussed below:

1. Do the proposed changes involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No

   The proposed TS changes affect the protective and mitigative capabilities of the plant; none of the changes impact the initiation or probability of occurrence of any accident.

   The consequences of accidents evaluated in the FSAR that could be affected by this proposed change are those in which the steam generator water level trip functions are credited for initiating a protective or mitigative function. These transients and accidents have been analyzed and all relevant event acceptance criteria were shown to be satisfied. The radiological dose consequences are unaffected. Therefore, there is no increase in the consequences of an accident previously evaluated.

   The actual proposed setpoint values were determined using an uncertainty methodology previously approved by the NRC for this application. These values provide adequate assurance that required protective and mitigative functions will be initiated as assumed in the transient and accident analyses. Therefore, there is no increase in the consequences of an accident previously evaluated.

   The proposed revisions to the $\Delta 76$ steam generator inventory, required to ensure that the steam generators can provide an effective heat sink, are consistent with the current design requirements. Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Do the proposed changes create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No

   No new accident scenarios, transient precursors, failure mechanisms, or limiting single failures are introduced as a result of these changes. There will be no adverse effect or challenges imposed on any safety-related system as a result of these changes. There are no changes which would cause the malfunction of safety-related equipment, assumed to be operable in the accident analyses, as a result of the proposed Technical Specification changes. No new equipment performance burdens are imposed. The possibility of a new or different malfunction-of safety-related equipment is not created. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. Do the proposed changes involve a significant reduction in a margin of safety?

   Response: No

   The proposed changes to the Steam Generator Water Level -Low-Low and Steam Generator Water Level –High-High trip function setpoints protect the assumed safety analysis limits established in the transient and accident analyses. When used in the transient and accident analyses, all relevant event acceptance criteria are satisfied. Therefore, these proposed changes do not result in the reduction in a margin of safety.

   The proposed changes to the Δ76 steam generator inventory requirements, which ensure the steam generators can function as an effective heat sink during required shutdown operating modes, are consistent with the existing design and licensing bases. Therefore, these proposed changes do not result in the reduction in a margin of safety.

Based on the above evaluations, TXU Power concludes that the proposed amendment presents no significant hazards under the standards set forth in 10CFR50.92(c) and, accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Applicable Regulatory Requirements/Criteria

As it relates to this License Amendment Request, the Reactor Protection System (consisting of the Reactor Trip System and the Engineered Safety Features Actuation System) is designed to meet the requirements of 10 CFR 50, Appendix A, GDC 20, "Protection system functions," which requires that the protection system be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety. The specified acceptable fuel design limits are described in NUREG-0800 (the Standard Review Plan). The steam generator water level trip functions are an integral part of this protection.

The use of the steam generators as an integral part of the redundant decay heat removal system conforms to the requirements of 10 CFR 50, Appendix A, GDC 34, "Residual Heat Removal," which requires that the safety function of the Residual Heat Removal System to be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

TXU Power has determined that the proposed amendment would change requirements with respect to the installation or use of a facility component located within the restricted area, as defined in 10CFR20, or would change an inspection or surveillance requirement. TXU Power has evaluated the proposed changes and has determined that the changes do not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amount of effluent that may be released offsite, or (iii) a significant increase in the individual or cumulative occupational radiation exposure. Accordingly, the proposed change meets the eligibility criterion for categorical exclusion set forth in 10CFR51.22 (c)(9). Therefore, pursuant to 10CFR51.22 (b), an environmental assessment of the proposed change is not required.

7.0 REFERENCES

7.1 TXX-05127, "License Amendment Request (LAR) 05-05 Revision To Technical Specification 3.7.10, "Control Room Emergency Filtration/Pressurization System (CREFS)" (ADAMS Accession Number ML052380403).

7.2 TXX-05037, "Request For Review Of Previously Submitted Licensee Topical Reports." (ADAMS Accession Number ML050590178).

7.3 TXX-06011, "License Amendment Request (LAR) 05-06 Revision To Technical Specification 5.6.5 "Revise Listing of LOCA and Non-LOCA Analysis Methodologies."

7.4 WCAP-12123, "Westinghouse Setpoint Methodology for Protection Systems Comanche Peak Unit 1, Revision 1," Revision 2, April, 1989.

7.5 NUREG-0797, "Safety Evaluation Report Related to the Operation of Comanche Peak Steam Electric Station, Units 1 and 2," Supplement 22, January 1990.

ATTACHMENT 2 to TXX-06001

PROPOSED TECHNICAL SPECIFICATION CHANGES (MARK-UP)

Pages	INSERTS (1 page)
	3.3-17
	3.3-32
	3.3-33
	3.4-10
	3.4-13
	3.4-14
	3.4-16

INSERT 1:

If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

INSERT 2:

The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Nominal Trip Setpoint, or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in a document controlled under 10 CFR 50.59.

Table 3.3.1-1 (page 3 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE(a)
10. Reactor Coolant Flow - Low	1(g)	3 per loop	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 88.6% of indicated loop flow (Unit 1) ≥ 88.8% of indicated loop flow (Unit 2)
11. Not Used					
12. Undervoltage RCPs	1(g)	1 per bus	M	SR 3.3.1.9 SR 3.3.1.10 SR 3.3.1.16	≥ 4753 V
13. Underfrequency RCPs	1(g)	1 per bus	M	SR 3.3.1.9 SR 3.3.1.10 SR 3.3.1.16	≥ 57.06 Hz
14. Steam Generator (SG) Water Level Low-Low (l)	1, 2	4 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ ~~23.1~~% of narrow range instrument span (Unit 1) ≥ 33.4% of narrow range instrument span (Unit 2)
15. Not Used.					
16. Turbine Trip					
a. Low Fluid Oil Pressure	1(j)	3	O	SR 3.3.1.10 SR 3.3.1.15	≥ 46.6 psig
b. Turbine Stop Valve Closure	1(j)	4	P	SR 3.3.1.10 SR 3.3.1.15	≥ 1% open

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(q) (r)

(q) [INSERT 1]
(r) [INSERT 2]

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(g) Above the P-7 (Low Power Reactor Trips Block) interlock.
(j) Above the P-9 (Power Range Neutron Flux) interlock.
(l) The applicable MODES for these channels in Table 3.3.2-1 are more restrictive.

Table 3.3.2-1 (page 4 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE(a)
5. Turbine Trip and Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays	1, 2(j)	2 trains	H	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
b. SG Water Level -- High High (P-14)	1, 2(j)	3 per SG(p)	I	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10 (q) (r)	≤ ~~84.3~~ 86% of narrow range span (Unit 1) ≤83.5% of narrow range span (Unit 2)
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(j) Except when all MFIVs and associated bypass valves are closed and de-activated or isolated by a closed manual valve.
(p) A channel selected for use as an input to the SG water level controller must be declared inoperable.

(q) [INSERT 1]
(r) [INSERT 2]

Table 3.3.2-1 (page 5 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE(a)
6. Auxiliary Feedwater					
a. Automatic Actuation Logic and Actuation Relays (Solid State Protection System)	1, 2, 3	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
b. Not Used.					
c. SG Water Level Low-Low	1, 2, 3	4 per SG	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10 (q) (r)	~~>23.1~~% of narrow range span (Unit 1) ≥33.4% of narrow range span (Unit 2)
d. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
e. Loss of Offsite Power	1, 2, 3	1 per train	F	SR 3.3.2.7 SR 3.3.2.9 SR 3.3.2.10	NA
f. Not Used.					
g. Trip of all Main Feedwater Pumps	1, 2	2 per AFW pump	J	SR 3.3.2.8	NA
h. Not Used.					

≥36

(continued)

(a) The Allowable Value defines the limiting safety system settins. See the Bases for the Trip Setpoints.

(q) [INSERT 1]
(r) [INSERT 2]

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify required RCS loops are in operation.	12 hours
SR 3.4.5.2	Verify steam generator secondary side water levels are ~~≥ 10%~~ for required RCS loops.	12 hours
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

≥38% (Unit 1) and ≥10% (Unit 2)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	12 hours
SR 3.4.6.2	Verify SG secondary side water levels are ~~≥ 10%~~ for required RCS loops.	12 hours
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

≥38% (Unit 1) and ≥10% (Unit 2)

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops — MODE 5, Loops Filled

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side water level of at least two steam generators (SGs) shall be ~~≥ 10%~~ ≥38% (Unit 1) and ≥10% (Unit 2).

----------NOTES----------

1. The ~~RHR~~ pump of the loop in operation may be removed from operation for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet the SDM of LCO 3.1.1; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. One required RHR loop may be inoperable for up to 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

3. No reactor coolant pump shall be started with any RCS cold leg temperature ≤ 350°F unless the secondary side water temperature of each SG is ≤ 50°F above each of the RCS cold leg temperatures.

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

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APPLICABILITY: MODE 5 with RCS loops filled

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.4.7.2	Verify SG secondary side water level is ~~≥ 10%~~ in required SGs.	12 hours
SR 3.4.7.3	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	7 days

≥38% (Unit 1) and ≥10% (Unit 2)

ATTACHMENT 3 to TXX-06001

PROPOSED TECHNICAL SPECIFICATIONS BASES CHANGES
(Markup For Information Only)

Pages	INSERTS (2 pages)
	B 3.3-57
	B 3.3-59
	B 3.3-65
	B 3.3-115
	B 3.3-117
	B 3.3-121
	B 3.3-122
	B 3.4-28
	B 3.4-33
	B 3.4-35
	B 3.4-37
	B 3.4-38
	B 3.4-39

INSERT 3:

SR 3.3.1.7 for selected Functions is also modified by two Notes (q and r) as identified in Table 3.3.1-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing.

INSERT 4:

SR 3.3.1.10 for selected Functions is also modified by two Notes (q and r) as identified in Table 3.3.1-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note (r) requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing.

INSERTS

INSERT 5:

SR 3.3.2.5 for selected Functions is modified by two Notes (q and r) as identified in Table 3.3.2-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing.

INSERT 6:

SR 3.3.2.9 for selected Functions is also modified by two Notes (q and r) as identified in Table 3.3.2-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note (r) requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing.

INSERTS

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.6 (continued)

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

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT every 184 days. A COT is performed on each required channel to ensure the channel will perform the intended Function. | 38

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

SR 3.3.1.7 is modified by two Notes. Note 1 provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3. Note 2 requires that the quarterly COT for the source range instrumentation include verification by observation of the associated permissive annunciator window that the P-6 and P-10 interlocks are in their required state for the existing unit conditions.

The Frequency of 184 days is justified in Reference 12. | 38

SR 3.3.1.8

SR 3.3.1.8 is the performance of a COT as described in SR 3.3.1.7, and it is modified by the same Note that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit conditions. The Frequency is modified by a Note that allows this

(continued)

INSERT 3

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.9 (continued)

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

SR 3.3.1.10

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. This SR is modified by Note 1 stating that N-16 detectors are excluded from the CHANNEL CALIBRATION because the unit must be in at least MODE 1 to obtain N-16 indications. However, after achieving equilibrium conditions in MODE 1, detector plateau curves should be obtained, evaluated and compared to manufacturer's data. | 9 | 9

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

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

SR 3.3.1.10 is modified by Note 2 stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. This surveillance does not include verification of time delay relays. These relays are verified via response time testing per SR 3.3.1.16. Whenever an RTD is replaced in Functions 6 or 7, the next required CHANNEL CALIBRATION of the RTDs is accomplished by an inplace cross calibration that compares other sensing elements with the recently installed element. | 9

The SR is modified by Note 3 stating that, prior to entry into MODES 2 or 1, power and intermediate range detector plateau verification is not required to be performed until 72 hours after achieving equilibrium conditions with THERMAL POWER $\geq$ 90% RTP. | 9

(continued)

INSERT 4

Table B 3.3.1-1 (page 2 of 2)
Reactor Trip System Setpoints

Function	Nominal Trip Setpoint	
14. Steam Generator Water Level - Low-Low	~~25~~% NR (Unit 1) 35.4% NR (Unit 2)	7
15. Not Used.		
16. Turbine Trip		7
a. Low Fluid Oil Pressure	59 psig	7
b. Turbine Stop Valve Closure	1% open	7
17. SI Input form ESFAS	NA	
18. Reactor Trip System Interlocks		
a. Intermediate Range Neutron Flux, P-6	1×10^{-10} amps	7
b. Low Power Reactor Trips Block, P-7	NA	
c. Power Range Neutron Flux, P-8	48% of RTP	
d. Power Range Neutron Flux, P-9	50% of RTP	7
e. Power Range Neutron Flux, P-10	10% of RTP	
f. Turbine First Stage Pressure, P-13	10% turbine power	
19. Reactor Trip Breakers	NA	
20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	NA	
21. Automatic Trip Logic	NA	

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.5

SR 3.3.2.5 is the performance of a COT.

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

The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint calculation. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint calculation.

The Frequency of 184 days is justified in Reference 13. I

SR 3.3.2.6

SR 3.3.2.6 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation mode is either allowed to function, or is placed in a condition where the relay contact operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation mode is prevented from operation by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing contacts operated by the slave relay. This test is performed every 92 days. The Frequency is adequate, based on industry operating experience, considering instrument reliability and operating history data.

INSERT 5

For ESFAS slave relays and auxiliary relays which are Westinghouse type AR relays, the SLAVE RELAY TEST is performed every 18 months. The Frequency is based on the slave relay reliability assessment presented in Reference 10. This reliability assessment is relay specific and applies only to Westinghouse type AR relays with AC coils. Note that, for normally energized applications, the relays may require periodic replacement in accordance with the guidance given in Reference 10.

SR 3.3.2.7

SR 3.3.2.7 is the performance of a TADOT every 31 days. This test is a check of the Loss of Offsite Power Function.

The SR is modified by a Note that excludes verification of setpoints for relays. Relay setpoints require elaborate bench calibration and are

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.9 (continued)

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

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

This SR is modified by a Note stating that this test should include verification that the time constants are adjusted to the prescribed values where applicable.

INSERT 6

SR 3.3.2.10

This SR ensures the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the accident analysis. Response Time testing, required channels, and acceptance criteria are included in the Technical Requirements Manual (Ref. 7). For each Functional Unit to which this SR applies, at least one ESF function has a required response time but not necessarily all associated ESF functions. No credit was taken in the safety analyses for those channels with response time listed as N.A. When the response time for a function in the TRM is NA, no specific testing need be performed to comply with this SR. Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the Trip Setpoint value at the sensor, to the point at which the equipment in both trains reaches the required functional state (e.g., pumps at rated discharge pressure, valves in full open or closed position).

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

(continued)

Table B 3.3.2-1 (page 2 of 3)
ESFAS Trip Setpoints

Function	Nominal Trip Setpoint	
3. Containment Isolation (continued)		
b. Phase B Isolation		
(1) Manual Initiation	NA	
(2) Automatic Actuation Logic and Actuation Relays	NA	
(3) Containment Pressure - High 3	18.2 psig	7
4. Steam Line Isolation		
a. Manual Initiation	NA	
b. Automatic Actuation Logic and Actuation Relays	NA	
c. Containment Pressure - High 2	6.2 psig	7
d. Steam Line Pressure		
(1) Low	605 psig $\tau_1 \geq 50$ seconds $\tau_2 \leq 5$ seconds	7
(2) Negative Rate - High	100 psi $\tau \geq 50$ seconds	7
5. Turbine Trip and Feedwater Isolation		
a. Automatic Actuation Logic and Actuation Relays	NA	
b. SG Water Level - High-High (P-14)	~~82.4~~% NR (Unit 1) 81.5% NR (Unit 2)	~~7~~
c. Safety Injection	See Function 1.	

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(continued)
~~(continued)~~

Table B 3.3.2-1 (page 3 of 3)
ESFAS Trip Setpoints

Function	Nominal Trip Setpoint
6. Auxiliary Feedwater	
a. Automatic Actuation Logic and Actuation Relays (SSPS)	NA
b. Not Used	
c. SG Water Level - Low-Low	~~25~~% NR (Unit 1) 35.4% NR (Unit 2)
d. Safety Injection	See Function 1.
e. Loss of Power	NA
f. Not Used	
g. Trip of All Main Feedwater Pumps	NA
h. Not Used.	
7. Automatic Switchover to Containment Sump	
a. Automatic Actuation Logic and Actuation Relays	NA
b. Refueling Water Storage Tank (RWST) Level - Low-Low Coincident with Safety Injection	45.0% span
8. ESFAS Interlocks	
a. Reactor Trip, P-4	NA
b. Pressurizer Pressure, P-11	1960 psig

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7

8

7

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loops are in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ~~≥ 10%~~ for required RCS loops. If the SG secondary side narrow range water level is ~~< 10%~~, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

SR 3.4.5.3

Verification that the required RCPs are OPERABLE ensures that safety analyses limits are met. The requirement also ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCPs.

REFERENCES None.

≥38% (Unit 1) and ≥10% (Unit 2)

<38% (Unit 1) and <10% (Unit 2)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ~~≥ 10%~~. If the SG secondary side narrow range water level is ~~< 10%~~, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.6.3

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, f needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. 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.

REFERENCES None.

≥38% (Unit 1) and ≥10% (Unit 2)

<38% (Unit 1) and <10% (Unit 2)

BASES (continued)

APPLICABLE SAFETY ANALYSES

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 RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining two SGs with secondary side water levels above ~~10%~~ to provide an alternate method for decay heat removal via natural circulation. In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation.

RCS Loops C MODE 5 (Loops Filled) satisfy Criterion 4 of 10CFR50.36(c)(2)(ii).

38% (Unit 1) and 10% (Unit 2)

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side water level ≥ ~~10%~~. One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side water levels ≥ ~~10%~~. Should the operating RHR loop fail, the SGs could be used to remove the decay heat via natural circulation.

Note 1 permits all RHR pumps to be removed from operation ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are required to be performed without flow or pump noise. The 1 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

(continued)

≥38% (Unit 1) and ≥10% (Unit 2)

BASES (continued)

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least two SGs is required to be ~~≥ 10%~~ .

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODES 1 and 2";
LCO 3.4.5, "RCS Loops — MODE 3";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SGs have secondary side water levels ~~<10%~~, redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water levels. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

(continued)

≥38% (Unit 1) and ≥10% (Unit 2)

<38% (Unit 1) and <10% (Unit 2)

BASES

ACTIONS (continued)

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Notes 1 and 4, or if no loop is OPERABLE, all operations involving introduction of coolant, into the RCS, with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent inadvertent criticality during a boron dilution, forced circulation from at least one RCP is required to provide proper mixing and preserve the margin to criticality in this type of operation. Suspending the introduction of coolant, into the RCS, with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Times reflect the importance of maintaining operation for heat removal. 29 29

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring their secondary side narrow range water levels are ~~≥ 10%~~ ≥38% (Unit 1) and ≥10% (Unit 2) ensures an alternate decay heat removal method via natural circulation in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this Surveillance is not needed. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary side water level is ~~≥ 10%~~ in at least two SGs, this Surveillance is not needed. 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.

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation."

≥38% (Unit 1) and ≥10% (Unit 2)

ATTACHMENT 4 to TXX-06001

RETYPED TECHNICAL SPECIFICATION PAGES

Pages	**3.3-17**
	3.3-32
	3.3-33
	3.4-10
	3.4-13
	3.4-14
	3.4-16

Table 3.3.1-1 (page 3 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE(a)
10. Reactor Coolant Flow - Low	1(g)	3 per loop	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 88.6% of indicated loop flow (Unit 1) ≥ 88.8% of indicated loop flow (Unit 2)
11. Not Used					
12. Undervoltage RCPs	1(g)	1 per bus	M	SR 3.3.1.9 SR 3.3.1.10 SR 3.3.1.16	≥ 4753 V
13. Underfrequency RCPs	1(g)	1 per bus	M	SR 3.3.1.9 SR 3.3.1.10 SR 3.3.1.16	≥ 57.06 Hz
14. Steam Generator (SG) Water Level Low-Low (l)	1, 2	4 per SG	E	SR 3.3.1.1 SR 3.3.1.7 (q)(r) SR 3.3.1.10 (q)(r) SR 3.3.1.16	≥ 36% of narrow range instrument span (Unit 1) ≥ 33.4% of narrow range instrument span (Unit 2)
15. Not Used.					
16. Turbine Trip					
a. Low Fluid Oil Pressure	1(j)	3	O	SR 3.3.1.10 SR 3.3.1.15	≥ 46.6 psig
b. Turbine Stop Valve Closure	1(j)	4	P	SR 3.3.1.10 SR 3.3.1.15	≥ 1% open

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(g) Above the P-7 (Low Power Reactor Trips Block) nterlock.
(j) Above the P-9 (Power Range Neutron Flux) interlock.
(l) The applicable MODES for these channels in Table 3.3.2-1 are more restrictive.
(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.
(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Trip Setpoint, or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in a document controlled under 10 CFR 50.59.

Table 3.3.2-1 (page 4 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
5. Turbine Trip and Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays	1, 2(j)	2 trains	H	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
b. SG Water Level -- High High (P-14)	1, 2(j)	3 per SG(p)	I	SR 3.3.2.1 SR 3.3.2.5 (q)(r) SR 3.3.2.9 (q)(r) SR 3.3.2.10	≤ 86% of narrow range span (Unit 1) ≤83.5% of narrow range span (Unit 2)
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(j) Except when all MFIVs and associated bypass valves are closed and de-activated or isolated by a closed manual valve.
(p) A channel selected for use as an input to the SG water level controller must be declared inoperable.
(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.
(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Trip Setpoint, or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in a document controlled under 10 CFR 50.59.

Table 3.3.2-1 (page 5 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE(a)
6. Auxiliary Feedwater					
a. Automatic Actuation Logic and Actuation Relays (Solid State Protection System)	1, 2, 3	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
b. Not Used.					
c. SG Water Level Low-Low	1, 2, 3	4 per SG	D	SR 3.3.2.1 SR 3.3.2.5 (q)(r) SR 3.3.2.9 (q)(r) SR 3.3.2.10	≥ 36% of narrow range span (Unit 1) ≥ 33.4% of narrow range span (Unit 2)
d. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
e. Loss of Offsite Power	1, 2, 3	1 per train	F	SR 3.3.2.7 SR 3.3.2.9 SR 3.3.2.10	NA
f. Not Used.					
g. Trip of all Main Feedwater Pumps	1, 2	2 per AFW pump	J	SR 3.3.2.8	NA
h. Not Used.					

(continued)

(a) The Allowable Value defines the limiting safety system settins. See the Bases for the Trip Setpoints.
(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.
(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Trip Setpoint, or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in a document controlled under 10 CFR 50.59.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify required RCS loops are in operation.	12 hours
SR 3.4.5.2	Verify steam generator secondary side water levels are ≥38% (Unit 1) and ≥10% (Unit 2) for required RCS loops.	12 hours
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	12 hours
SR 3.4.6.2	Verify SG secondary side water levels are ≥38% (Unit 1) and ≥10% (Unit 2) for required RCS loops.	12 hours
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops — MODE 5, Loops Filled

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side water level of at least two steam generators (SGs) shall be ≥38% (Unit 1) and ≥10% (Unit 2).

----------NOTES----------

1. The RHR pump of the loop in operation may be removed from operation for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet the SDM of LCO 3.1.1; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. One required RHR loop may be inoperable for up to 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

3. No reactor coolant pump shall be started with any RCS cold leg temperature ≤ 350°F unless the secondary side water temperature of each SG is ≤ 50°F above each of the RCS cold leg temperatures.

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

APPLICABILITY: MODE 5 with RCS loops filled

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.7.2	Verify SG secondary side water level is ≥38% (Unit 1) and ≥10% (Unit 2) in required SGs.	12 hours
SR 3.4.7.3	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	7 days

ATTACHMENT 5 to TXX-06001

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.6 (continued)

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

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT every 184 days. A COT is performed on each required channel to ensure the channel will perform the intended Function.

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

SR 3.3.1.7 is modified by two Notes. Note 1 provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3. Note 2 requires that the quarterly COT for the source range instrumentation include verification by observation of the associated permissive annunciator window that the P-6 and P-10 interlocks are in their required state for the existing unit conditions.

SR 3.3.1.7 for selected Functions is also modified by two Notes (q and r) as identified in Table 3.3.1-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

The Frequency of 184 days is justified in Reference 12.

SR 3.3.1.8

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

SR 3.3.1.9

SR 3.3.1.9 is the performance of a TADOT and is performed every 92 days, as justified in Reference 5.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.10

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. This SR is modified by Note 1 stating that N-16 detectors are excluded from the CHANNEL CALIBRATION because the unit must be in at least MODE 1 to obtain N-16 indications. However, after achieving equilibrium conditions in MODE 1, detector plateau curves should be obtained, evaluated and compared to manufacturer's data.

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

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

SR 3.3.1.10 is modified by Note 2 stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. This surveillance does not include verification of time delay relays. These relays are verified via response time testing per SR 3.3.1.16. Whenever an RTD is replaced in Functions 6 or 7, the next required CHANNEL CALIBRATION of the RTDs is accomplished by an inplace cross calibration that compares other sensing elements with the recently installed element.

The SR is modified by Note 3 stating that, prior to entry into MODES 2 or 1, power and intermediate range detector plateau verification is not required to be performed until 72 hours after achieving equilibrium conditions with THERMAL POWER $\geq$ 90% RTP.

SR 3.3.1.10 for selected Functions is also modified by two Notes (q and r) as identified in Table 3.3.1-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note (r) requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.10 (continued)

If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing.

SR 3.3.1.11

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 18 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. For the intermediate and power range channels, detector plateau curves are obtained, evaluated and compared to manufacturer's data. The CHANNEL CALIBRATION for the source range neutron detectors consists of obtaining the detector plateau curves, evaluating those curves, and comparing the curves to the manufacturer's data. Note 3 states that, prior to entry into MODES 2 or 1, the power and intermediate range detector plateau voltage verification is not required to be current until 72 hours after achieving equilibrium conditions with THERMAL POWER $\geq$ 90% RTP. Equilibrium conditions are achieved when the core is sufficiently stable at intended operating conditions to perform a meaningful detector plateau voltage verification. The allowance of 72 hours after equilibrium conditions are attained at the testing plateau provides sufficient time to allow power ascension testing to be conducted in a controlled and orderly manner at conditions that provide acceptable results and without introducing the potential for extended operation at high power levels with instrumentation that has not been verified to be OPERABLE for subsequent use. Operating experience has shown these components usually pass the Surveillance when performed on the 18 month Frequency.

SR 3.3.1.11 is modified by Note 2 stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. This surveillance does not include verification of time delay relays. These relays are verified via response time testing per SR 3.3.1.16.

SR 3.3.1.12

Not Used.

SR 3.3.1.13

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

(continued)

Table B 3.3.1-1 (page 2 of 2)
Reactor Trip System Setpoints

Function	Nominal Trip Setpoint
14. Steam Generator Water Level - Low-Low	38% NR (Unit 1) 35.4% NR (Unit 2)
15. Not Used.	
16. Turbine Trip	
a. Low Fluid Oil Pressure	59 psig
b. Turbine Stop Valve Closure	1% open
17. SI Input form ESFAS	NA
18. Reactor Trip System Interlocks	
a. Intermediate Range Neutron Flux, P-6	1×10^{-10} amps
b. Low Power Reactor Trips Block, P-7	NA
c. Power Range Neutron Flux, P-8	48% of RTP
d. Power Range Neutron Flux, P-9	50% of RTP
e. Power Range Neutron Flux, P-10	10% of RTP
f. Turbine First Stage Pressure, P-13	10% turbine power
19. Reactor Trip Breakers	NA
20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	NA
21. Automatic Trip Logic	NA

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.5

SR 3.3.2.5 is the performance of a COT.

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

The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint calculation. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint calculation.

SR 3.3.2.5 for selected Functions is modified by two Notes as identified in Table 3.3.2-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note (r) requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing.

The Frequency of 184 days is justified in Reference 13.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation mode is either allowed to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.6 (continued)

function, or is placed in a condition where the relay contact operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation mode is prevented from operation by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing contacts operated by the slave relay. This test is performed every 92 days. The Frequency is adequate, based on industry operating experience, considering instrument reliability and operating history data.

For ESFAS slave relays and auxiliary relays which are Westinghouse type AR relays, the SLAVE RELAY TEST is performed every 18 months. The Frequency is based on the slave relay reliability assessment presented in Reference 10. This reliability assessment is relay specific and applies only to Westinghouse type AR relays with AC coils. Note that, for normally energized applications, the relays may require periodic replacement in accordance with the guidance given in Reference 10.

SR 3.3.2.7

SR 3.3.2.7 is the performance of a TADOT every 31 days. This test is a check of the Loss of Offsite Power Function.

The SR is modified by a Note that excludes verification of setpoints for relays. Relay setpoints require elaborate bench calibration and areverified during CHANNEL CALIBRATION. The SR is modified by a second note that excludes the actuation of final devices from the surveillance testing. The start of the auxiliary feedwater pumps during this SR is unnecessary as these pumps are adequately tested by the SRs for LCO 3.7.5. The Frequency is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.8

SR 3.3.2.8 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and AFW pump start on trip of all MFW pumps. The Safety Injection TADOT shall independently verify the OPERABILITY of the handswitch undervoltage and shunt trip contacts for both the Reactor Trip Breakers and Reactor Trip Bypass Breakers as well as the contacts for safety injection actuation. It is performed every 18 months. As a minimum, each Manual Actuation Function is tested up to, but not including, the master relay coils. This test overlaps with the master relay coil testing performed in accordance with SR 3.3.2.4. The Frequency is adequate, based on industry operating experience and is consistent with the typical refueling cycle. The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation Functions. The manual initiation Functions have no associated setpoints.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.9

SR 3.3.2.9 is the performance of a CHANNEL CALIBRATION.

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

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

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

This SR is modified by a Note stating that this test should include verification that the time constants are adjusted to the prescribed values where applicable.

SR 3.3.2.9 for selected Functions is also modified by two Notes as identified in Table 3.3.2-1. The selected Functions are those Functions that are LSSS and whose instruments are not mechanical devices (i.e. limit switches, float switches, and proximity detectors). Mechanical devices are excluded since it is not possible to trend these devices and develop as-left or as-found limits in the same manner as other instrumentation. The first Note (q) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design-basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition for OPERABILITY. The second Note (r) requires that the as-left setting for the instrument be returned to within the as-left tolerance of the Nominal Trip Setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left instrument setting cannot be returned to a setting within the as-left tolerance, then the instrument channel shall be declared inoperable. This second Note (r) requirement identifies the Limited Safety System Setting and allows an independent verification that the Allowable Value is the appropriate least conservative as-found value during SR testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.10

This SR ensures the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the accident analysis. Response Time testing, required channels, and acceptance criteria are included in the Technical Requirements Manual (Ref. 7). For each Functional Unit to which this SR applies, at least one ESF function has a required response time but not necessarily all associated ESF functions.

No credit was taken in the safety analyses for those channels with response time listed as N.A. When the response time for a function in the TRM is NA, no specific testing need be performed to comply with this SR. Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the Trip Setpoint value at the sensor, to the point at which the equipment in both trains reaches the required functional state (e.g., pumps at rated discharge pressure, valves in full open or closed position).

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

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor, signal processing and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be used for selected components provided that the components and methodology for verification have been previously NRC approved.

ESF RESPONSE TIME tests are performed on an 18 month STAGGERED TEST BASIS. The testing shall include at least one train such that both trains are tested at least once per 36 months. Testing of the final actuation devices, which make up the bulk of the response time, is included in the testing of each channel. The final actuation device in one train is tested with each channel. Therefore, staggered testing results in response time verification of these devices every 18 months. The 18 month Frequency is consistent with the typical refueling cycle and is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences. Response time verification in lieu of actual testing may be performed on ESFAS components in accordance with reference 11.

This SR is modified by a Note that clarifies that the turbine driven AFW pump is tested within 24 hours after reaching 532 psig in the SGs.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.11

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

The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Function tested has no associated setpoint.

SR 3.3.2.12

SR 3.3.2.12 is the performance of a CHANNEL CALIBRATION.

A CHANNEL CALIBRATION is performed every 9 months. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter within the necessary range and accuracy.

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

The Frequency of 9 months is based on the assumption of an 9 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

REFERENCES

1. FSAR, Chapter 6.
2. FSAR, Chapter 7.
3. FSAR, Chapter 15.
4. IEEE-279-1971.
5. 10 CFR 50.49.
6. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
7. Technical Requirements Manual.
8. WCAP-10271-P-A, Supplement 3, September 1990.
9. "Westinghouse Setpoint Methodology for Protection Systems Comanche Peak Unit 1, Revision 1," WCAP-12123, Revision 2, April, 1989.
10. WCAP-13877-P-A, Revision 2, August 2000.
11. "Elimination of Periodic Protection Channel Response Time Tests", WCAP-14036-P-A, Revision 1, October 6, 1998.
12. "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," WCAP-14333-P-A, Revision 1, October 1998.
13. "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," WCAP-15376-P-A, Revision 1, March 2003.

Table B 3.3.2-1 (page 2 of 3)
ESFAS Trip Setpoints

Function	Nominal Trip Setpoint
3. Containment Isolation (continued)	
b. Phase B Isolation	
(1) Manual Initiation	NA
(2) Automatic Actuation Logic and Actuation Relays	NA
(3) Containment Pressure - High 3	18.2 psig
4. Steam Line Isolation	
a. Manual Initiation	NA
b. Automatic Actuation Logic and Actuation Relays	NA
c. Containment Pressure - High 2	6.2 psig
d. Steam Line Pressure	
(1) Low	605 psig $\tau_1 \geq 50$ seconds $\tau_2 \leq 5$ seconds
(2) Negative Rate - High	100 psi $\tau \geq 50$ seconds
5. Turbine Trip and Feedwater Isolation	
a. Automatic Actuation Logic and Actuation Relays	NA
b. SG Water Level - High-High (P-14)	84% NR (Unit 1) 81.5% NR (Unit 2)
c. Safety Injection	See Function 1.

(continued)

Table B 3.3.2-1 (page 3 of 3)
ESFAS Trip Setpoints

Function	Nominal Trip Setpoint
6. Auxiliary Feedwater	
a. Automatic Actuation Logic and Actuation Relays (SSPS)	NA
b. Not Used	
c. SG Water Level - Low-Low	38% NR (Unit 1) 35.4% NR (Unit 2)
d. Safety Injection	See Function 1.
e. Loss of Power	NA
f. Not Used	
g. Trip of All Main Feedwater Pumps	NA
h. Not Used.	
7. Automatic Switchover to Containment Sump	
a. Automatic Actuation Logic and Actuation Relays	NA
b. Refueling Water Storage Tank (RWST) Level - Low-Low Coincident with Safety Injection	45.0% span
8. ESFAS Interlocks	
a. Reactor Trip, P-4	NA
b. Pressurizer Pressure, P-11	1950 psig

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loops are in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥38% (Unit 1) and ≥10% (Unit 2) for required RCS loops. If the SG secondary side narrow range water level is <38% (Unit 1) and <10% (Unit 2) the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

SR 3.4.5.3

Verification that the required RCPs are OPERABLE ensures that safety analyses limits are met. The requirement also ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCPs.

REFERENCES None.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥38% (Unit 1) and ≥10% (Unit 2). If the SG secondary side narrow range water level is <38% (Unit 1) and <10% (Unit 2), the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.6.3

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. 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.

REFERENCES None.

BASES (continued)

APPLICABLE SAFETY ANALYSES

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 RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining two SGs with secondary side water levels above 38% (Unit 1) and 10% (Unit 2) to provide an alternate method for decay heat removal via natural circulation. In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation.

RCS Loops C MODE 5 (Loops Filled) satisfy Criterion 4 of 10CFR50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side water level ≥38% (Unit 1) and ≥10% (Unit 2). One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side water levels ≥38% (Unit 1) and ≥10% (Unit 2). Should the operating RHR loop fail, the SGs could be used to remove the decay heat via natural circulation.

Note 1 permits all RHR pumps to be removed from operation ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are required to be performed without flow or pump noise. The 1 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

(continued)

BASES (continued)

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least two SGs is required to be ≥38% (Unit 1) and ≥10% (Unit 2).

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops — MODES 1 and 2";
LCO 3.4.5, "RCS Loops — MODE 3";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SGs have secondary side water levels <38% (Unit 1) and <10% (Unit 2), redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water levels. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Notes 1 and 4, or if no loop is OPERABLE, all operations involving introduction of coolant, into the RCS, with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent inadvertent criticality during a boron dilution, forced circulation from at least one RCP is required to provide proper mixing and preserve the margin to criticality in this type of operation. Suspending the introduction of coolant, into the RCS, with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring their secondary side narrow range water levels are ≥38% (Unit 1) and ≥10% (Unit 2) ensures an alternate decay heat removal method via natural circulation in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this Surveillance is not needed. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary side water level is ≥38% (Unit 1) and ≥10% (Unit 2) in at least two SGs, this Surveillance is not needed. 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.

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation."