DCP/NRC1523

December 2, 2002

Attachment 1

Table 1, "List of Westinghouse's Responses to RAIs Transmitted in DCP/NRC1523"

Docket No. 52-006

DCP/NRC1523

December 2, 2002

ATTACHMENT 1

Table 1 "List of Westinghouse's Responses to RAIs as Related to Technical Specifications Transmitted in DCP/NRC1523"	
100.003	630.029
250.003	630.030
261.011	630.024
440.101	630.025
440.102 Rev 1	630.026
440.108	630.027
630.001	630.031
630.002	630.032
630.003	630.033
630.004	630.034
630.005	630.035
630.006	630.036
630.007	630.037
630.008	630.038
630.009	630.039
630.010	630.040
630.011	630.041
630.012	630.042
630.013	630.043
630.014	630.044
630.015	630.045
630.016	630.046
630.017	630.047
630.018	630.048
630.019	630.049
630.020	630.050
630.021	630.051
630.022	630.052
630.023	630.053
630.028	720.039

DCP/NRC1523

December 2, 2002

Attachment 2

Westinghouse Non-Proprietary Response

to US Nuclear Regulatory Commission

Requests for Additional Information

dated November 2002

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 100.003

Question:

With respect to the regulatory treatment of non-safety systems (RTNSS), is the process you utilized to determine which AP1000 systems are designated as RTNSS systems (and subsequently covered by your investment protection short-term availability controls stated in Section 16.3 of the DCD) consistent with that utilized for the AP600 and the process discussed in NUREG-1512, "Final Safety Evaluation Report Related to Certification of the AP600 Standard Design," Chapter 22? If any differences exist, please describe. Has an AP1000-specific review (based on the AP1000 design and probabilistic risk assessment (PRA)) of which systems should have regulatory treatment been performed? If not, please justify.

Westinghouse Response:

WCAP-15985 "AP1000 Implementation of the Regulatory Treatment of Nonsafety-Related Systems Process" provides the basis for the implementation of the RTNSS policy statement. The AP1000 implementation of the RTNSS policy statement is consistent with the approach that was taken for the AP600. Note that PRA sensitivity studies with nonsafety systems failed were used to evaluate the importance of nonsafety features in PRA accident mitigation, instead of the focused PRA sensitivity study. The AP1000 PRA, revision 0, includes the CMF sensitivity study; the LRF sensitivity study was performed recently based on the response to RAI 720.057 and will be added to the PRA in revision 1.

Use of these sensitivity studies increases the need for passive safety feature actuation signals since non-safety AC power is assumed to be available after each accident except for loss of offsite power. As a result, some non-safety manual Diverse Actuation System (DAS) controls are required to meet the licensing PRA safety goals. These manual DAS controls are captured as RTNSS important and additional regulatory oversight is provided. Since these manual DAS controls meet the technical specification screening criteria for PRA importance, a Technical Specification is added on these manual DAS controls. The additional Technical Specification is included in the revised AP1000 Technical Specifications that are submitted as part of the response to RAI 630.001.

These DAS manual controls were the only additional non-safety featured captured in the AP1000 RTNSS evaluation. The list of non-safety features that have short-term availability controls is the same for AP1000 and AP600.

Design Control Document (DCD) Revision:

See the attached Technical Specification for DAS that is included in the revised AP1000 Technical Specifications.

PRA Revision:

None

RAI Number 100.003

3.3 INSTRUMENTATION

3.3.5 Diverse Actuation System (DAS) Manual Controls

LCO 3.3.5 The DAS manual controls for each function in Table 3.3.5-1 shall be operable.

APPLICABILITY: According to Table 3.3.5-1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more manual DAS controls inoperable.	A.1 Restore DAS manual controls to OPERABLE status.	30 days
B. Completion Time of Required Action A not met for inoperable DAS manual reactor trip control.	B.1 Perform SR 3.3.1.5.	Once per 31 days on a STAGGERED TEST BASIS
	AND	
	B.2 Restore all controls to OPERABLE status.	Prior to entering MODE 2 following next MODE 5 entry
C. Completion Time of Required Action A not met for inoperable DAS manual actuation control other than reactor trip.	C.1 Perform SR 3.3.2.3.	Once per 31 days on a STAGGERED TEST BASIS
	AND	
	C.2 Restore all controls to OPERABLE status.	Prior to entering MODE 2 following next MODE 5 entry

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Completion Time of Required Action B not met. OR Completion Time of Required Action C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	-----------------NOTE----------------- Verify of setpoint not required. -------------------------------------- Perform TRIP ACTUATION DEVICE OPERATIONAL TEST (TADOT).	24 months

RAI Number 100.003

B 3.3 INSTRUMENTATION

B 3.3.5 Diverse Actuation System (DAS) Manual Controls

BASES

BACKGROUND

The Diverse Actuation System (DAS) manual controls provide backup controls in case of common mode failure of the Protection and Safety Monitoring System (PMS) automatic and manual actuations evaluated in the AP1000 PRA. These controls are not credited for mitigating accidents in the DCD Chapter 15 analyses.

The specific DAS controls were selected based on PRA risk importance as discussed in Reference 1. As noted in Reference 1, electrical power for these controls and instrument indications need not be covered by Technical Specifications. The rational is that these controls use the same nonsafety-related power supply used by the plant control system. This power is required to be available to support normal operation of the plant. With offsite power available, there are several sources to provide this power including AC power to non-Class 1E battery chargers, AC power to rectifiers, and non-Class 1E batteries. As a result, with offsite power available it is very likely that power will be available for these DAS controls. If offsite power is not available, then there is still the likelihood that the non-1E batteries or the non-1E diesel generators will be available. Even if these sources are unavailable, the desired actions will occur without operator action for the more probable events. The rods will insert automatically on loss of offsite power. The passive residual heat removal heat exchanger (PRHR HX), core makeup tanks (CMT), passive containment cooling system (PCS), and containment isolation features are initiated by operation of fail-safe, air-operated valves. If all offsite and onsite AC power is lost, the instrument air system will depressurize by the time these functions are needed in the 1-hour time frame.

Instrument readouts are expected to be available even in case of complete failure of the PMS due to common cause failure. These instruments include both DAS and PLS instruments. As discussed above, it is expected that AC power will be available to power the instruments. Even if the operators have no instrument indications, they are

(continued)

BASES

BACKGROUND (continued)

expected to actuate the controls most likely to be needed (PRHR HX, CMT, PCS, and containment isolation). If all AC power fails, then the rods will drop and the air-operated valves will go to their fail-safe positions.

The DAS uses equipment from sensor output to the final actuated device that is diverse from the PMS to automatically initiate a reactor trip, or to manually actuate the identified safety-related equipment. DCD Section 7.7.1.11 (Ref. 2) provides a description of the DAS.

APPLICABLE SAFETY ANALYSES

The DAS manual controls are required to provide a diverse capability to manually trip the reactor and actuate the specified safety-related equipment, based on risk importance in the AP1000 PRA.

The DAS manual controls are not credited for mitigating accidents in the DCD Chapter 15 safety analyses.

The AP1000 PRA, Appendix A, provides additional information, including the thermal and hydraulic analyses of success sequences used in the PRA.

The DAS manual controls satisfy Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The DAS LCO provides the requirements for the OPERABILITY of the DAS manual trip and actuation controls necessary to place the reactor in a shutdown condition and to remove decay heat in the event that the PMS automatic actuation and manual controls are inoperable.

APPLICABILITY

The DAS manual controls are required to be OPERABLE in the MODES specified in Table 3.3.5-1.

The manual DAS reactor trip control is required to be operable in MODES 1 and 2 to mitigate the effects of an ATWS event occurring during power operation.

The other manual DAS actuation controls are required to be available in the plant MODES specified, based on the need

(continued)

BASES

APPLICABILITY (continued)

for operator action to actuate the specified components during events that may occur in these various plant conditions, as identified in the AP1000 PRA.

ACTIONS

A.1

Condition A applies when one or more DAS manual controls are inoperable.

The Required Action A.1 to restore the inoperable DAS manual control(s) to OPERABLE status within 30 days is reasonable because the DAS is a separate and diverse non-safety backup system for the manual reactor trip and manual safety-related equipment actuation controls. The 30-day Completion Time allows sufficient time to repair an inoperable manual DAS control but ensures the control is repaired to provide backup protection.

B.1 and B.2

Condition B applies when Required Action A cannot be completed for the DAS manual reactor trip control within the required completion time of 30 days.

Required Action B.1 requires SR 3.3.1.5, "Perform TADOT" for the reactor trip breakers, is to be performed once per 31 days, instead on once every 92 days. The predominant failure requiring the DAS manual reactor trip control is common mode failure of the reactor trip breakers. This change in surveillance frequency for testing the reactor trip breakers increases the likelihood that a common mode failure of the reactor trip breakers would be detected while the DAS manual reactor trip control is inoperable. This reduces the likelihood that a diverse manual reactor trip is required. It is not required to perform a TADOT for the manual actuation control. The manual reactor trip control is very simple, highly reliable, and does not use software in the circuitry.

Action B.2 requires that the inoperable DAS manual reactor trip control be restored to OPERABLE status prior to entering MODE 2 following any plant shutdown to MODE 5 while the control is inoperable. This ACTION is provided to ensure that all DAS manual controls are restored to OPERABLE status following the next plant shutdown.

(continued)

RAI Number 100.003

BASES

ACTIONS (continued)

C.1 and C.2

Condition C applies when Required Action A cannot be completed for any DAS manual actuation control (other than reactor trip) within the required completion time of 30 days.

Required Action C.1 requires SR 3.3.2.2, "Perform ACTUATION LOGIC TEST," to be performed once per 31 days, instead on once every 92 days. The predominant failure requiring the DAS manual reactor trip control is common mode failure of the PMS actuation logic software or hardware. This change in surveillance frequency for actuation logic testing increases the likelihood that a common mode failure of the PMS actuation logic from either cause would be detected while any DAS manual actuation control is inoperable. This reduces the likelihood that a diverse component actuation is required. It is not required to perform a TADOT for the manual actuation control device since the manual actuation control devices are very simple and highly reliable.

Action C.2 requires that the inoperable DAS manual actuation control(s) be restored to OPERABLE status prior to entering MODE 2 following any plant shutdown to MODE 5 while the control is inoperable. This ACTION is provided to ensure that all DAS manual controls are restored to OPERABLE status following the next plant shutdown.

D.1 and D.2

Condition D is entered if the Required Action associated with Condition B or C is not met within the required Completion Time.

Required Actions D.1 and D.2 ensure that the plant is placed in a condition where the probability and consequences of an event are minimized. The allowed Completion Times are reasonable based on plant operating experience, for reaching the required plant conditions from full power conditions in an orderly manner, without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT of the DAS manual trip and actuation controls for the specified safety-related equipment. This TADOT is performed every 24 months.

The Frequency is based on the known reliability of the DAS functions and has been shown to be acceptable through operating experience.

The SR is modified by a Note that excludes verification of the setpoints from the TADOT. The functions have no setpoints associated with them.

REFERENCES

1. WCAP-15985, "AP1000 Implementation of the Regulatory Treatment of Nonsafety-Related Systems Process," November 2002.

2. DCD, Section 7.7.1.11.

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 250.003

Question:

The requirements for the Steam Generator (SG) Tube Surveillance Program are contained in technical specification (TS) 5.5.5. This TS specifies that "SG tube sample size selection, sample size expansion, inspection results classification criteria, tube inspection frequency, plugging and repair limits, and specific definitions and limits be in accordance with [Regulatory Guide 1.83, Revision [ ], date]." (Square bracketed information is to be defined when TSs are determined for the combined license applicant.) The most recent revision of RG 1.83 is Revision 1, dated July 1975. Specifying technical specification inspection requirements to be in accordance with this RG is inappropriate since the RG contains guidance and not requirements, i.e., recommended surveillances are written in terms of actions that should be taken. The guidance in this RG was superceded by the SG technical specifications in various documents, the most recent of which being NUREG-0452, Revision 4, "Standard Technical Specifications (STS) for Westinghouse Pressurized Water Reactors." The TS surveillance requirements for all domestic SGs are very similar, if not identical, to those in NUREG-0452, Revision 4, and under the Improved Standard Technical Specification program these surveillance requirements are unchanged. These requirements contain some essential surveillance requirements missing from RG 1.83, Revision1, such as definitive sample expansion criteria. In addition, TS Section 5.6.8, SG Tube Inspection Report, refers to condition C-3 for submitting certain reports; C-3 is not defined in RG 1.83 or elsewhere in the TSs although it is defined in the STS. Please revise the SG Tube Surveillance Program TSs to be consistent with the surveillance requirements contained in STS in NUREG-0452, Revision 4. (Section 5.4.2)

Westinghouse Response:

The Steam Generator (SG) Tube Surveillance Technical Specifications (TSs) will be revised to be consistent with the SG surveillance requirements included in NUREG 1431, V1, Rev. 2, "Standard Technical Specifications Westinghouse Plants" dated April 2001. The technical specification surveillance requirements for all domestic SGs under NUREG-0452, Rev. 5 are very similar and remain unchanged under NUREG-1431, V1, Rev 2. Please note that AP1000 does not include an "Operating Basis Earthquake" (OBE) in its design basis, and therefore TS 5.5.5.3.c.2. and 5.5.5.4.a.7 instead refer to "one-third of the Safe Shutdown Earthquake" (SSE) consistent with DCD section 3.7. The changes are identified below in the Design Control Document (DCD) Revision portion of this RAI. The TS revision is included in the TS revision in response to RAI 630.001.

Design Control Document (DCD) Revision:

Replace TS 5.5.5 with the following:

5.5.5 Steam Generator (SG) Tube Surveillance Program

The provisions of SR 3.0.2 are applicable to the SG Tube Surveillance Program Test Frequencies.

5.5.5.0 Each steam generator shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program.

5.5.5.1 Steam Generator Sample Selection and Inspection

Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 5.5.5-1.

5.5.5.2 Steam Generator Tube Sample Selection and Inspection

The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Table 5.5.5-2. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 5.5.5.3, and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 5.5.5.4. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in all steam generators. The tubes selected for these inspections shall be selected on a random basis except:

a. Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50% of the tubes inspected shall be from these critical areas.

b. The first sample of tubes selected for each inservice inspection (subsequent to the preservice inspection) of each steam generator shall include:

   1. All nonplugged tubes that previously had detectable wall penetrations greater than 20%.

   2. Tubes in those areas where experience has indicated potential problems.

   3. A tube inspection (pursuant to Specification 5.5.5.4.a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current

probe for a tube inspection, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

c. The tubes selected as the second and third samples (if required by Table 5.5.5-2) during each inservice inspection may be subjected to a partial tube inspection provided:

1. The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found.

2. The inspections include those portions of the tubes where imperfections were previously found.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1 % of the inspected tubes are defective.

Note: In all inspections, previously degraded tubes must exhibit significant (greater than 10%) further wall penetrations to be included in the above percentage calculations.

5.5.5.3 Inspection Frequencies

The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections following service under AVT conditions, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 5.5.5-2 at 40 month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 5.5.5.3.a; the interval may then be extended to a maximum of once per 40 months.

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 5.5.5-2 during the shutdown subsequent to any of the following conditions:

1. Primary-to-secondary tube leaks (not including leaks originating from tube-to-tubesheet welds) in excess of the limits of Specification 3.4.8.

2. A seismic occurrence greater than one-third of the Safe Shutdown Earthquake.

3. A loss-of-coolant accident requiring actuation of the engineered safeguards.

4. A main steam line or feedwater line break.

5.5.5.4 <u>Acceptance Criteria</u>

a. As used in this Specification:

1. <u>Imperfection</u> means an exception to the dimensions, finish or contour of a tube from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal wall thickness, if detectable, may be considered as imperfections.

2 Degradation means a service-induced cracking wastage, wear or general corrosion occurring on either inside or outside of a tube.

3. Degraded Tube means a tube that contains imperfections greater than or equal to 20% of the nominal wall thickness caused by degradation.

4. % Degradation means the percentage of the tube wall thickness affected or removed by degradation.

5. Defect means an imperfection of such severity that it exceeds the plugging limit. A tube containing a defect is defective.

6. Plugging Limit means the imperfection depth at or beyond which the tube shall be removed from service by plugging and is greater than or equal to 40% of the nominal tube wall thickness.

7. Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of a one-third of the Safe Shutdown Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 5.5.5.3.c, above.

8. Tube Inspection means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg.

9. Preservice Inspection means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed using the equipment and techniques expected to be used during subsequent inservice inspections.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plugging of all tubes exceeding the plugging limit) required by Table 5.5.5-2.

Table 5.5.5-1

No. of Steam Generators per Unit	**Two**
First Inservice Inspection	**One**
Second and Subsequent Inservice Inspections	**One***

*The other steam generator not inspected during the first inservice inspection shall be reinspected. The third and subsequent inspections may be limited to one steam generator on a rotating schedule encompassing 3 N% of the tubes (where N is the number of steam generators in the plant) if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. If the condition of the tubes in one steam generator are found to be more severe than in the other steam generator, the SG sampling sequence at the subsequent inspection shall be modified to examine the steam generator with the more severe condition.

Table 5.5.5-2
Steam Generator Tube Inspection

<table>
<tr><th rowspan="2">Sample Size</th><th colspan="2">1st Sample Inspection</th><th colspan="2">2nd Sample Inspection</th><th colspan="2">3rd Sample Inspection</th></tr>
<tr><th>Result</th><th>Action Required</th><th>Result</th><th>Action Required</th><th>Result</th><th>Action Required</th></tr>
<tr><td rowspan="9">A minimum of S Tubes per SG</td><td>C-1</td><td>None</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
<tr><td rowspan="5">C-2</td><td rowspan="5">Plug defective tubes and inspect additional 2S tubes in this SG</td><td>C-1</td><td>None</td><td>N/A</td><td>N/A</td></tr>
<tr><td rowspan="3">C-2</td><td rowspan="3">Plug defective tubes and inspect additional 4S tubes in this SG</td><td>C-1</td><td>None</td></tr>
<tr><td>C-2</td><td>Plug defective tubes</td></tr>
<tr><td>C-3</td><td>Perform action for C-3 result of first sample</td></tr>
<tr><td>C-3</td><td>Perform action for C-3 result of first sample</td><td>N/A</td><td>N/A</td></tr>
<tr><td rowspan="3">C-3</td><td rowspan="3">Inspect all tubes in this SG, plug defective tubes and inspect 2S tubes in each other SG

Notification to NRC pursuant to 10 CFR 50.73</td><td>All other SGs are C-1</td><td>None</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Some SGs C-2 but no additional SGs are C-3</td><td>Perform action for C-2 result of second sample</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Additional SG is C-3</td><td>Inspect all tubes in each SG and plug defective tubes.
Notification to NRC pursuant to 10 CFR 50.73</td><td>N/A</td><td>N/A</td></tr>
</table>

$S = \frac{3N}{n}\%$ Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

Replace TS 5.6.8 with the following:

5.6.8 Steam Generator Tube Inspection Report

a. Following each inservice inspection of steam generator tubes, the number of tubes plugged in each steam generator shall be reported to the Commission within 15 days of the completion of the plugging effort.

b. The complete results of the steam generator tube inservice inspection shall be submitted to the Commission within 12 months following the completion of the inspection. This Report shall include:

   1. Number and extent of tubes inspected.
   2. Location and percent of wall-thickness penetration for each indication of an imperfection.
   3. Identification of tubes plugged.

c. Results of steam generator tube inspections which fall into Category C-3 shall be considered a Reportable Event and shall be reported pursuant to 10 CFR 50.73 prior to resumption of plant operation. The written report shall provide a description of investigations conducted to determine the cause of the tube degradation and corrective measures taken to prevent recurrence.

PRA Revision:

None.

5.5 Programs and Manuals

5.5.4 Inservice Testing Program (continued)

ASME Boiler and Pressure Vessel Code and applicable Addenda Terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities;

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

5.5.5 Steam Generator (SG) Tube Surveillance Program

The provisions of SR 3.0.2 are applicable to the SG Tube Surveillance Program Test Frequencies.

5.5.5.0 Each steam generator shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program.

5.5.5.1 Steam Generator Sample Selection and Inspection

Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 5.5.5-1.

(continued)

5.5 Programs and Manuals

5.5.5 Steam Generator (SG) Tube Surveillance Program (continued)

5.5.5.2 Steam Generator Tube Sample Selection and Inspection

The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Table 5.5.5-2. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 5.5.5.3, and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 5.5.5.4. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in all steam generators. The tubes selected for these inspections shall be selected on a random basis except:

a. Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50% of the tubes inspected shall be from these critical areas.

b. The first sample of tubes selected for each inservice inspection (subsequent to the preservice inspection) of each steam generator shall include:

   1. All nonplugged tubes that previously had detectable wall penetrations greater than 20%.

   2. Tubes in those areas where experience has indicated potential problems.

   3. A tube inspection (pursuant to Specification 5.5.5.4.a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube inspection, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

c. The tubes selected as the second and third samples (if required by Table 5.5.5-2) during each inservice inspection may be subjected to a partial tube inspection provided:

   1. The tubes selected for these samples include the tubes from those areas of the tube sheet array

where tubes with imperfections were previously found.

2. The inspections include those portions of the tubes where imperfections were previously found.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

Note: In all inspections, previously degraded tubes must exhibit significant (greater than 10%) further wall penetrations to be included in the above percentage calculations.

5.5.5.3 Inspection Frequencies

The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections following service under AVT conditions, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 5.5.5-2 at 40 month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 5.5.5.3.a; the interval may then be extended to a maximum of once per 40 months.

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 5.5.5-2 during the shutdown subsequent to any of the following conditions:

1. Primary-to-secondary tube leaks (not including leaks originating from tube-to-tubesheet welds) in excess of the limits of Specification 3.4.8.

2. A seismic occurrence greater than one-third of the Safe Shutdown Earthquake.

3. A loss-of-coolant accident requiring actuation of the engineered safeguards.

4. A main steam line or feedwater line break.

5.5.5.4 <u>Acceptance Criteria</u>

a. As used in this Specification:

1. <u>Imperfection</u> means an exception to the dimensions, finish or contour of a tube from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal wall thickness, if detectable, may be considered as imperfections.

2. <u>Degradation</u> means a service-induced cracking wastage, wear or general corrosion occurring on either inside or outside of a tube.

3. <u>Degraded Tube</u> means a tube that contains imperfections greater than or equal to 20% of the nominal wall thickness caused by degradation.

4. _% Degradation_ means the percentage of the tube wall thickness affected or removed by degradation.

5. _Defect_ means an imperfection of such severity that it exceeds the plugging limit. A tube containing a defect is defective.

6. _Plugging Limit_ means the imperfection depth at or beyond which the tube shall be removed from service by plugging and is greater than or equal to 40% of the nominal tube wall thickness.

7. _Unserviceable_ describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of a one-third of the Safe Shutdown Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 5.5.5.3.c, above.

8. _Tube Inspection_ means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg.

9. _Preservice Inspection_ means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed using the equipment and techniques expected to be used during subsequent inservice inspections.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plugging of all tubes exceeding the plugging limit) required by Table 5.5.5-2.

Table 5.5.5-1 (page 1 of 1)

No. of Steam Generators per Unit	Two
First Inservice Inspection	One
Second and Subsequent Inservice Inspections	One*

*The other steam generator not inspected during the first inservice inspection shall be reinspected. The third and subsequent inspections may be limited to one steam generator on a rotating schedule encompassing 3 N% of the tubes (where N is the number of steam generators in the plant) if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. If the condition of the tubes in one steam generator are found to be more severe than in the other steam generator, the SG sampling sequence at the subsequent inspection shall be modified to examine the steam generator with the more severe condition.

Table 5.5.5-2 (page 1 of 1)
Steam Generator Tube Inspection

	1st Sample Inspection		2nd Sample Inspection		3rd Sample Inspection	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S Tubes per SG	C-1	None	N/A	N/A	N/A	N/A
	C-2	Plug defective tubes and inspect additional 2S tubes in this SG	C-1	None	N/A	N/A
			C-2	Plug defective tubes and inspect additional 4S tubes in this SG	C-1	None
					C-2	Plug defective tubes
					C-3	Perform action for C-3 result of first sample
			C-3	Perform action for C-3 result of first sample	N/A	N/A
	C-3	Inspect all tubes in this SG, plug defective tubes and inspect 2S tubes in each other SG Notification to NRC pursuant to 10 CFR 50.73	All other SGs are C-1	None	N/A	N/A
			Some SGs C-2 but no additional SGs are C-3	Perform action for C-2 result of second sample	N/A	N/A
			Additional SG is C-3	Inspect all tubes in each SG and plug defective tubes Notification to NRC pursuant to 10 CFR 50.73	N/A	N/A

$S = \frac{3N}{n}\%$ Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

5.6 Reporting Requirements (continued)

5.6.8 Steam Generator Tube Inspection Report

a. Following each inservice inspection of steam generator tubes, the number of tubes plugged in each steam generator shall be reported to the Commission within 15 days of the completion of the plugging effort.

b. The complete results of the steam generator tube inservice inspection shall be submitted to the Commission within 12 months following the completion of the inspection. This Report shall include:

   1. Number and extent of tubes inspected.

   2. Location and percent of wall-thickness penetration for each indication of an imperfection.

   3. Identification of tubes plugged.

c. Results of steam generator tube inspections which fall into Category C-3 shall be considered a Reportable Event and shall be reported pursuant to 10 CFR 50.73 prior to resumption of plant operation. This written report shall provide a description of investigations conducted to determine the cause of the tube degradation and corrective measures taken to prevent recurrence.

RAI Number: 261.011

Question:

Based on Revision 0 to the AP1000 DCD (redline/strikeout version comparing the AP600 and AP1000 DCDs), WCAP-13856, "AP600 Implementation of the Regulatory Treatment of Nonsafety Related System Process," Revision 1, January 1998 has been deleted as a reference (this document is listed as Reference 6 in Section 14.3.9). SECY-95-132 "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems (RTNSS) in Passive Plant Designs," dated May 22, 1995, sets forth the Commissions policy with respect to those systems in passive light water reactors that are not designated as safety-related but may have a significant role to play in accident and consequence mitigation. Westinghouse has deleted reference to this document and does not mention the RTNSS process for the AP1000. Please justify why this information is being deleted from the DCD.

Please provide a discussion of how the AP1000 design certification application aligns with the Commission's policy on the RTNSS in passive plant designs as documented in SECY-95-132. Please discuss the process utilized to determine which defense-in-depth systems fall into the RTNSS category. Is WCAP-13856 applicable to AP1000? If there are any similarities in the implementation of determining which systems fall into the RTNSS category for the AP1000 as compared to the AP600, please state so. If there are any differences please describe and discuss. Are there any changes in the systems that fall into the RTNSS category when comparing the AP1000 design to the AP600 design?

Westinghouse Response:

WCAP-15985 "AP1000 Implementation of the Regulatory Treatment of Nonsafety-Related Systems Process" provides the basis for the implementation of the RTNSS policy statement. The AP1000 implementation of the RTNSS policy statement is consistent with the approach that was taken for the AP600. Note that PRA sensitivity studies with nonsafety systems failed were used to evaluate the importance of nonsafety features in PRA accident mitigation, instead of the focused PRA sensitivity study. The AP1000 PRA, revision 0, includes the CMF sensitivity study; the LRF sensitivity study was performed recently based on the response to RAI 720.057 and will be added to the PRA in revision 1.

Use of these sensitivity studies increases the need for passive safety feature actuation signals since non-safety AC power is assumed to be available after each accident except for loss of offsite power. As a result, some non-safety manual Diverse Actuation System (DAS) controls are required to meet the licensing PRA safety goals. These manual DAS controls are captured as RTNSS important and additional regulatory oversight is provided. Since these manual DAS controls meet the technical specification screening criteria for PRA importance, a Technical Specification is added on these manual DAS controls. The additional Technical Specification is included in the revised AP1000 Technical Specifications that are submitted as part of the response to RAI 630.001.

These DAS manual controls were the only additional non-safety featured captured in the AP1000 RTNSS evaluation. The list of non-safety features that have short-term availability controls is the same for AP1000 and AP600.

Design Control Document (DCD) Revision:

See the attached Technical Specification for DAS that is included in the revised AP1000 Technical Specifications.

PRA Revision:

None

RAI Number 261.011

3.3 INSTRUMENTATION

3.3.5 Diverse Actuation System (DAS) Manual Controls

LCO 3.3.5 The DAS manual controls for each function in Table 3.3.5-1 shall be operable.

APPLICABILITY: According to Table 3.3.5-1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more manual DAS controls inoperable.	A.1 Restore DAS manual controls to OPERABLE status.	30 days
B. Completion Time of Required Action A not met for inoperable DAS manual reactor trip control.	B.1 Perform SR 3.3.1.5.	Once per 31 days on a STAGGERED TEST BASIS
	<u>AND</u>	
	B.2 Restore all controls to OPERABLE status.	Prior to entering MODE 2 following next MODE 5 entry
C. Completion Time of Required Action A not met for inoperable DAS manual actuation control other than reactor trip.	C.1 Perform SR 3.3.2.3.	Once per 31 days on a STAGGERED TEST BASIS
	<u>AND</u>	
	C.2 Restore all controls to OPERABLE status.	Prior to entering MODE 2 following next MODE 5 entry

(continued)

RAI Number 261.011

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Completion Time of Required Action B not met. OR Completion Time of Required Action C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	-----------------NOTE ----------------- Verify of setpoint not required. -- Perform TRIP ACTUATION DEVICE OPERATIONAL TEST (TADOT).	24 months

B 3.3 INSTRUMENTATION

B 3.3.5 Diverse Actuation System (DAS) Manual Controls

BASES

BACKGROUND

The Diverse Actuation System (DAS) manual controls provide backup controls in case of common mode failure of the Protection and Safety Monitoring System (PMS) automatic and manual actuations evaluated in the AP1000 PRA. These controls are not credited for mitigating accidents in the DCD Chapter 15 analyses.

The specific DAS controls were selected based on PRA risk importance as discussed in Reference 1. As noted in Reference 1, electrical power for these controls and instrument indications need not be covered by Technical Specifications. The rational is that these controls use the same nonsafety-related power supply used by the plant control system. This power is required to be available to support normal operation of the plant. With offsite power available, there are several sources to provide this power including AC power to non-Class 1E battery chargers, AC power to rectifiers, and non-Class 1E batteries. As a result, with offsite power available it is very likely that power will be available for these DAS controls. If offsite power is not available, then there is still the likelihood that the non-1E batteries or the non-1E diesel generators will be available. Even if these sources are unavailable, the desired actions will occur without operator action for the more probable events. The rods will insert automatically on loss of offsite power. The passive residual heat removal heat exchanger (PRHR HX), core makeup tanks (CMT), passive containment cooling system (PCS), and containment isolation features are initiated by operation of fail-safe, air-operated valves. If all offsite and onsite AC power is lost, the instrument air system will depressurize by the time these functions are needed in the 1-hour time frame.

Instrument readouts are expected to be available even in case of complete failure of the PMS due to common cause failure. These instruments include both DAS and PLS instruments. As discussed above, it is expected that AC power will be available to power the instruments. Even if the operators have no instrument indications, they are

(continued)

RAI Number 261.011

BASES

BACKGROUND (continued)	expected to actuate the controls most likely to be needed (PRHR HX, CMT, PCS, and containment isolation). If all AC power fails, then the rods will drop and the air-operated valves will go to their fail-safe positions. The DAS uses equipment from sensor output to the final actuated device that is diverse from the PMS to automatically initiate a reactor trip, or to manually actuate the identified safety-related equipment. DCD Section 7.7.1.11 (Ref. 2) provides a description of the DAS.
APPLICABLE SAFETY ANALYSES	The DAS manual controls are required to provide a diverse capability to manually trip the reactor and actuate the specified safety-related equipment, based on risk importance in the AP1000 PRA. The DAS manual controls are not credited for mitigating accidents in the DCD Chapter 15 safety analyses. The AP1000 PRA, Appendix A, provides additional information, including the thermal and hydraulic analyses of success sequences used in the PRA. The DAS manual controls satisfy Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	The DAS LCO provides the requirements for the OPERABILITY of the DAS manual trip and actuation controls necessary to place the reactor in a shutdown condition and to remove decay heat in the event that the PMS automatic actuation and manual controls are inoperable.
APPLICABILITY	The DAS manual controls are required to be OPERABLE in the MODES specified in Table 3.3.5-1. The manual DAS reactor trip control is required to be operable in MODES 1 and 2 to mitigate the effects of an ATWS event occurring during power operation. The other manual DAS actuation controls are required to be available in the plant MODES specified, based on the need

(continued)

BASES

APPLICABILITY (continued)

for operator action to actuate the specified components during events that may occur in these various plant conditions, as identified in the AP1000 PRA.

ACTIONS

A.1

Condition A applies when one or more DAS manual controls are inoperable.

The Required Action A.1 to restore the inoperable DAS manual control(s) to OPERABLE status within 30 days is reasonable because the DAS is a separate and diverse non-safety backup system for the manual reactor trip and manual safety-related equipment actuation controls. The 30-day Completion Time allows sufficient time to repair an inoperable manual DAS control but ensures the control is repaired to provide backup protection.

B.1 and B.2

Condition B applies when Required Action A cannot be completed for the DAS manual reactor trip control within the required completion time of 30 days.

Required Action B.1 requires SR 3.3.1.5, "Perform TADOT" for the reactor trip breakers, is to be performed once per 31 days, instead on once every 92 days. The predominant failure requiring the DAS manual reactor trip control is common mode failure of the reactor trip breakers. This change in surveillance frequency for testing the reactor trip breakers increases the likelihood that a common mode failure of the reactor trip breakers would be detected while the DAS manual reactor trip control is inoperable. This reduces the likelihood that a diverse manual reactor trip is required. It is not required to perform a TADOT for the manual actuation control. The manual reactor trip control is very simple, highly reliable, and does not use software in the circuitry.

Action B.2 requires that the inoperable DAS manual reactor trip control be restored to OPERABLE status prior to entering MODE 2 following any plant shutdown to MODE 5 while the control is inoperable. This ACTION is provided to ensure that all DAS manual controls are restored to OPERABLE status following the next plant shutdown.

(continued)

RAI Number 261.011

BASES

ACTIONS (continued)

C.1 and C.2

Condition C applies when Required Action A cannot be completed for any DAS manual actuation control (other than reactor trip) within the required completion time of 30 days.

Required Action C.1 requires SR 3.3.2.2, "Perform ACTUATION LOGIC TEST," to be performed once per 31 days, instead on once every 92 days. The predominant failure requiring the DAS manual reactor trip control is common mode failure of the PMS actuation logic software or hardware. This change in surveillance frequency for actuation logic testing increases the likelihood that a common mode failure of the PMS actuation logic from either cause would be detected while any DAS manual actuation control is inoperable. This reduces the likelihood that a diverse component actuation is required. It is not required to perform a TADOT for the manual actuation control device since the manual actuation control devices are very simple and highly reliable.

Action C.2 requires that the inoperable DAS manual actuation control(s) be restored to OPERABLE status prior to entering MODE 2 following any plant shutdown to MODE 5 while the control is inoperable. This ACTION is provided to ensure that all DAS manual controls are restored to OPERABLE status following the next plant shutdown.

D.1 and D.2

Condition D is entered if the Required Action associated with Condition B or C is not met within the required Completion Time.

Required Actions D.1 and D.2 ensure that the plant is placed in a condition where the probability and consequences of an event are minimized. The allowed Completion Times are reasonable based on plant operating experience, for reaching the required plant conditions from full power conditions in an orderly manner, without challenging plant systems.

(continued)

RAI Number 261.011

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT of the DAS manual trip and actuation controls for the specified safety-related equipment. This TADOT is performed every 24 months.

The Frequency is based on the known reliability of the DAS functions and has been shown to be acceptable through operating experience.

The SR is modified by a Note that excludes verification of the setpoints from the TADOT. The functions have no setpoints associated with them.

REFERENCES

1. WCAP-15985, "AP1000 Implementation of the Regulatory Treatment of Nonsafety-Related Systems Process," November 2002.
2. DCD, Section 7.7.1.11.

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.101

Question:

In TS 3.2.1, "Heat Flux Hot Channel Factor (F_Q (Z)) (F_Q Methodology)," the Required Actions for Conditions A and B are different from those specified in TS 3.2.1B, "Heat Flux Hot Channel Factor (F_Q (Z)) (RAOC - W(Z) Methodology)," of NUREG-1431, Rev. 2, "Standard Technical Specifications, Westinghouse Plants" (WSTS). For example, WSTS Required Action A.4 requires the performance of SR 3.2.1.1 and 3.2.1.2, whereas AP1000 TS Required Action A.4 requires the performance of SR 3.2.1.1 only. Also WSTS Required Actions B.2, B.3, and B.4 are not included in the AP1000 TS.

Explain the differences and why they are acceptable for AP1000.

Westinghouse Response:

As discussed in the response to RAI 630.001, the AP1000 Technical Specifications will be updated to reference NUREG-1431, Rev.2.

Therefore, TS 3.2.1 will be revised to be consistent with TS 3.2.1B of NUREG-1431, Rev. 2, which includes the identified differences.

Design Control Document (DCD) Revision:

See the attached revision to TS 3.2.1.

PRA Revision:

None

RAI Number 440.101

3.2 POWER DISTRIBUTION LIMITS

3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$) (F_Q Methodology)

LCO 3.2.1 $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1 with On-line Power Distribution Monitoring System (OPDMS) inoperable.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
----------NOTE----------- Required Action A.4 shall be completed whenever this Condition is entered. -------------------------		
A. $F_Q^C(Z)$ not within limit.	A.1 Reduce THERMAL POWER $\geq$ 1% RTP for each 1% $F_Q^C(Z)$ exceeds limit.	15 minutes after each $F_Q^C(Z)$ determination
	AND	
	A.2 Reduce Power Range Neutron Flux High trip setpoints $\geq$ 1% for each 1% $F_Q^C(Z)$ exceeds limit.	72 hours after each $F_Q^C(Z)$ determination
	AND	
	A.3 Reduce Overpower ΔT trip setpoints $\geq$ 1% for each 1% $F_Q^C(Z)$ exceeds limit.	72 hours after each $F_Q^C(Z)$ determination
	AND	

	A.4 Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the limit of Required Action A.1

(continued)

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
----------NOTE----------- Required Action B.4 shall be completed whenever this Condition is entered. -------------------------		
B. $F_Q^W(Z)$ not within limits.	B.1 Reduce AFD limits ≥ 1% for each 1% $F_Q^W(Z)$ exceeds limit.	4 hours
	<u>AND</u>	
	B.2 Reduce Power Range Neutron Flux - High trip setpoints ≥ 1% for each 1% that the maximum allowable power of the AFD limits is reduced.	72 hours
	<u>AND</u>	
	B.3 Reduce Overpower ΔT trip setpoints ≥ 1% for each 1% that the maximum allowable power of the AFD limits is reduced.	72 hours
	<u>AND</u>	
	B.4 Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the maximum allowable power of the AFD limits

RAI Number 440.101

C. Required Action and associated Completion Time not met.	C.1 Be in MODE 2.	6 hours

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.102 (Response Revision 1)

Question:

TS Limiting Condition of Operation (LCO) 3.2.5 specifies the operating limits of the power distribution parameters (peak kw/ft, $F_{\Delta H}^{N}$, and DNBR) monitored by the On-line Power Distribution Monitoring System (OPDMS). TS 5.6.5 lists WCAP-12472-P-A, "BEACON - Core Monitoring and Operation Support System," August 1994, and Addendum 1, May 1996, as the approved method used for the determination of the monitored power distribution parameters limits. TS 5.6.5 also contains a "REVIEWER'S NOTE" stating that additional power distribution control and surveillance methodologies (for MSHIM and OPDMS monitoring) are currently under development and will be added upon NRC approval...." Section 4.3.4 of Design Control Document (DCD) states that the Combined License applicant will reference an NRC-approved addendum to WCAP-12472-P-A covering AP1000 fixed incore detector.

Though the BEACON system described in WCAP-12472-P-A has been accepted by NRC for performing continuous on-line core monitoring and operations support functions for Westinghouse PWRs, its acceptance is limited to the current standard Westinghouse OPDMS with the use of movable incore detectors, on which the instrumentation data base in WCAP-12472-P-A and the staff evaluation were based. Since the AP1000 OPDMS uses fixed in-core detectors, in-core thermocouples, and loop temperature measurements, which differ sufficiently from these data base, an evaluation is required for the generic uncertainty components to determine if the assumptions made in the BEACON uncertainty analysis remains valid, and assure that the power peaking uncertainties for the enthalpy rise and heat flux provide 95 percent probability upper tolerance limits at the 95 percent confidence level. (Section 4.3.2.2.7 discusses experimental verification of power distribution analysis.)

When will Westinghouse submit the addendum to WCAP-12472 on AP1000 fixed incore detector?

Westinghouse Response (Revision 1):

While the original BEACON topical report was based on the use of moveable incore detectors, use of BEACON with fixed incore detector systems has been addressed through addendums to the BEACON Topical Report. These addendum were approved by the NRC. BEACON using fixed incore detectors signals has been used in two plants, one internationally and one non-tech spec surveillance version in the US.

Addendum 1 of WCAP-12472 -P-A was approved by the USNRC and issued as an approved version in January 2000. Addendum 1 addressed two key areas for the use of fixed incore detectors. First, it presented the methodology for using fixed incore detectors and described the uncertainty analysis methodology to be used in plants with fixed incore detectors. Data from different NSSS vendors plant types were used to demonstrate this methodology. The second area is the methodology used to model rhodium fixed incore detectors. The BEACON monitoring methodology is based on the ratio of the measured to predicted detector currents. Since Westinghouse plants had not used fixed incore detectors, the methodology for BEACON to predict a fixed incore detector current had not previously been presented to the NRC. This methodology is based on previsouly approved Westinghouse core physics methods.

Because of customer interest in a long-lived fixed incore detector material, the methodology to predict incore detector currents was extended in Addendum 2 to WCAP-12472. This addendum extended the fixed incore detector methods to include fixed detectors made of vanadium or platinum material. This addendum was reviewed and approved by the USNRC and the approved version of the topical report was released in May 2002.

Westinghouse does not believe that additional licensing of the BEACON system is required to support the AP1000. The specific effort will be determining the measurement variability of the selected fixed incore detector design and, using the methodology described in the BEACON Topical report including the addendums, to determine appropriate measurement uncertainties appropriate for the AP1000.

Design Control Document (DCD) Revision:

DCD Chapter 16, TS 5.6.5, pg. 5.0-19:

6. WCAP-12472-P-A, "BEACON Core Monitoring and Operations Support System," August 1994, ~~and~~ Addendum 1, May 1996 (Westinghouse Proprietary), and Addendum 2 March 2001 (Westinghouse Proprietary).

   (Methodology for Specification 3.2.5 - OPDMS - Monitored Power Distribution Parameters.)

~~REVIEWER'S NOTE~~

~~Additional power distribution control and surveillance methodologies (for MSHIM and OPDMS monitoring) are currently under development and will be added upon NRC approval. An NRC approved addendum to WCAP-12472-P-A covering AP1000 power distribution control and surveillance methodologies must be in place prior to generating an AP1000 specific version of this technical specification.~~

DCD Chapter 4, Sections 4.3.4 and 4.3.5:

4.3.4 Combined License Information

This section contains no requirement for additional information to be provided in support of the combined license. Combined License applicants referencing the AP1000 certified design will address changes to the reference design of the fuel, burnable absorber rods, rod cluster control assemblies, or initial core design from that presented in the DCD.

~~The Combined License applicant will reference an NRC approved addendum to WCAP-12472-P-A (Reference 4) covering AP1000 fixed incore detectors.~~

4.3.5 References

1. Bordelon, F. M, et al., "Westinghouse Reload Safety Evaluation Methodology," WCAP-9272-P-A, July 1985.

[2. *Davidson, S. L. (Ed.), "Fuel Criteria Evaluation Process," WCAP-12488-P-A (Proprietary) and WCAP-14204-A - (Nonproprietary), October 1994.*]*

3. ANSI N18.2-1973, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants."

4. Beard, C. L. and Morita, T., "BEACON: Core Monitoring and Operations Support System," WCAP-12472-P-A Proprietary) and WCAP-12473-P-A (Nonproprietary), August 1994, ~~and~~ Addendum 1, May 1996, and Addendum 2, March 2001.

DCD Chapter 1.6, Table 1.6-1 (Sheet 6 of 20):

Table 1.6-1 (Sheet 6 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
4.2	WCAP-8691	Fuel Rod Bow Evaluation, Revision 1, July 1979
	WCAP-9500-P-A (P) WCAP-9500-A	Reference Core Report 17x17 Optimized Fuel Assembly, May 1982
	WCAP-8236 (P) WCAP-8288	Safety Analysis of the 17x17 Fuel Assembly for Combined Seismic and Loss-of-Coolant Accident, December 1973
	WCAP-9401-P-A (P) WCAP-9402-A	Verification, Testing, and Analysis of the 17x17 Optimized Fuel Assembly, August 1981
	WCAP-9283	Integrity of Primary Piping Systems of Westinghouse Nuclear Power Plants During Postulated Seismic Events, March 1978
	WCAP-15063-P-A (P)	Westinghouse Improved Performance Analysis and Design Model (PAD 4.0), Rev. 1, July 2000
	WCAP-8377 (P)	Revised Clad Flattening Model, July 1974
4.3	WCAP-9272-P-A	Westinghouse Reload Safety Evaluation Methodology, July 1985
	[*WCAP-12488-P-A (P)* [*WCAP-14204-A*]*	*Fuel Criteria Evaluation Process, October 1994*]*
	WCAP-12472-P-A (P) WCAP-12473-P-A	BEACON: Core Monitoring and Operations Support System, August 1994, ~~and~~ Addendum 1, May 1996,

		Addendum 2, March 2001
	WCAP-8330	Westinghouse Anticipated Transients Without Reactor Trip Analysis, August 1974

DCD Chapter **1.6, Table 1.6-1 (Sheet 6 of 20):**

Table 1.8-2 (Sheet 3 of 6)

SUMMARY OF AP1000 STANDARD PLANT COMBINED LICENSE INFORMATION ITEMS

Item No.	Subject	Subsection
4.3-1	Changes to Reference Reactor Design	4.3.4
~~4.3-2~~	~~Fixed Incore Detectors~~	~~4.3-4~~
4.4-1	Changes to Reference Reactor Design	4.4.7
5.2-1	ASME Code and Addenda	5.2.6.1

PRA Revision:

None

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

2c. NUREG-0800, Standard Review Plan, U.S. Nuclear Regulatory Commission, Section 4.3, Nuclear Design, July 1981. Branch Technical Position CPB 4.3-1, Westinghouse Constant Axial Offset Control (CAOC), Rev. 2, July 1981.

(Methodology for Specification 3.2.3 - Axial Flux Difference (Constant Axial Offset Control).)

3. WCAP-10216-P-A, Revision 1A, "Relaxation of Constant Axial Offset Control FQ Surveillance Technical Specification," February 1994 (Westinghouse Proprietary).

(Methodology for Specifications 3.2.2 - Axial Flux Difference (Relaxed Axial Offset Control) and 3.2.1 - Heat Flux Hot Channel Factor (W(Z) surveillance requirements for FQ Methodology).)

4. WCAP-12945-P, Volumes 1-5, "Westinghouse Code Qualification Document for Best Estimate Loss of Coolant Accident Analysis," Revision 2, March 1998.

(Methodology for Specification 3.2.1 - Heat Flux Hot Channel Factor.)

5. WCAP-14807, "NOTRUMP Final Validation Report for AP600," R.L. Fittante et al., Revision 5, August 1998 and WCAP-5644, "AP1000 Code Applicability Report," Revision 0, May 2001.

(Methodology for Specification 3.2.1 - Heat Flux Hot Channel Factor.)

6. WCAP-12472-P-A, "BEACON Core Monitoring and Operations Support System," August 1994, Addendum 1, May 1996 (Westinghouse Proprietary), and Addendum 2 March 2001 (Westinghouse Proprietary).

(Methodology for Specification 3.2.5 - OPDMS - Monitored Power Distribution Parameters.)

(continued)

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.108

Question:

SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems in Passive Plant Designs," dated March 28, 1994, discusses the process for the resolution of regulatory treatment of non-safety systems (RTNSS), including the methodology for the selection of important non-safety systems, their reliability/availability missions, and regulatory oversight. Section 16.3 of DCD, "Investment Protection," specifies the Investment protection short-term availability controls for the important non-safety systems identified through the RTNSS process. Section 16.3.1 states that the importance of non-safety-related systems, structures and components (SSCs) in the AP1000 has been evaluated, using probabilistic risk assessment (PRA) insights to identify structures, systems, and components (SSCs) that are important in protecting the utilities investment and for preventing and mitigating severe accidents.

Provide a detailed AP1000-specific evaluation in accordance with the RTNSS process described in SECY-94-084 for identification of the important non-safety systems, and their reliability/availability missions, which forms the basis for Section 16-3 investment protection short-term availability controls.

Westinghouse Response:

WCAP-15985 "AP1000 Implementation of the Regulatory Treatment of Nonsafety-Related Systems Process" provides the basis for the implementation of the RTNSS policy statement. The AP1000 implementation of the RTNSS policy statement is consistent with the approach that was taken for the AP600. Note that PRA sensitivity studies with nonsafety systems failed were used to evaluate the importance of nonsafety features in PRA accident mitigation, instead of the focused PRA sensitivity study. The AP1000 PRA, revision 0, includes the CMF sensitivity study; the LRF sensitivity study was performed recently based on the response to RAI 720.057 and will be added to the PRA in revision 1.

Use of these sensitivity studies increases the need for passive safety feature actuation signals since non-safety AC power is assumed to be available after each accident except for loss of offsite power. As a result, some non-safety manual Diverse Actuation System (DAS) controls are required to meet the licensing PRA safety goals. These manual DAS controls are captured as RTNSS important and additional regulatory oversight is provided. Since these manual DAS controls meet the technical specification screening criteria for PRA importance, a Technical Specification is added on these manual DAS controls. The additional Technical Specification is included in the revised AP1000 Technical Specifications that are submitted as part of the response to RAI 630.001.

These DAS manual controls were the only additional non-safety featured captured in the AP1000 RTNSS evaluation. The list of non-safety features that have short-term availability controls is the same for AP1000 and AP600.

Design Control Document (DCD) Revision:

See the attached Technical Specification for DAS that is included in the revised AP1000 Technical Specifications.

PRA Revision:

None

3.3 INSTRUMENTATION

3.3.5 Diverse Actuation System (DAS) Manual Controls

LCO 3.3.5 The DAS manual controls for each function in Table 3.3.5-1 shall be operable.

APPLICABILITY: According to Table 3.3.5-1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more manual DAS controls inoperable.	A.1 Restore DAS manual controls to OPERABLE status.	30 days
B. Completion Time of Required Action A not met for inoperable DAS manual reactor trip control.	B.1 Perform SR 3.3.1.5.	Once per 31 days on a STAGGERED TEST BASIS
	AND	
	B.2 Restore all controls to OPERABLE status.	Prior to entering MODE 2 following next MODE 5 entry
C. Completion Time of Required Action A not met for inoperable DAS manual actuation control other than reactor trip.	C.1 Perform SR 3.3.2.3.	Once per 31 days on a STAGGERED TEST BASIS
	AND	
	C.2 Restore all controls to OPERABLE status.	Prior to entering MODE 2 following next MODE 5 entry

(continued)

RAI Number 440.108

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Completion Time of Required Action B not met. OR Completion Time of Required Action C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	-----------------NOTE----------------- Verify of setpoint not required. -------------------------------------- Perform TRIP ACTUATION DEVICE OPERATIONAL TEST (TADOT).	24 months

RAI Number 440.108

B 3.3 INSTRUMENTATION

B 3.3.5 Diverse Actuation System (DAS) Manual Controls

BASES

BACKGROUND

The Diverse Actuation System (DAS) manual controls provide backup controls in case of common mode failure of the Protection and Safety Monitoring System (PMS) automatic and manual actuations evaluated in the AP1000 PRA. These controls are not credited for mitigating accidents in the DCD Chapter 15 analyses.

The specific DAS controls were selected based on PRA risk importance as discussed in Reference 1. As noted in Reference 1, electrical power for these controls and instrument indications need not be covered by Technical Specifications. The rational is that these controls use the same nonsafety-related power supply used by the plant control system. This power is required to be available to support normal operation of the plant. With offsite power available, there are several sources to provide this power including AC power to non-Class 1E battery chargers, AC power to rectifiers, and non-Class 1E batteries. As a result, with offsite power available it is very likely that power will be available for these DAS controls. If offsite power is not available, then there is still the likelihood that the non-1E batteries or the non-1E diesel generators will be available. Even if these sources are unavailable, the desired actions will occur without operator action for the more probable events. The rods will insert automatically on loss of offsite power. The passive residual heat removal heat exchanger (PRHR HX), core makeup tanks (CMT), passive containment cooling system (PCS), and containment isolation features are initiated by operation of fail-safe, air-operated valves. If all offsite and onsite AC power is lost, the instrument air system will depressurize by the time these functions are needed in the 1-hour time frame.

Instrument readouts are expected to be available even in case of complete failure of the PMS due to common cause failure. These instruments include both DAS and PLS instruments. As discussed above, it is expected that AC power will be available to power the instruments. Even if the operators have no instrument indications, they are

(continued)

RAI Number 440.108

BASES

BACKGROUND (continued)	expected to actuate the controls most likely to be needed (PRHR HX, CMT, PCS, and containment isolation). If all AC power fails, then the rods will drop and the air-operated valves will go to their fail-safe positions. The DAS uses equipment from sensor output to the final actuated device that is diverse from the PMS to automatically initiate a reactor trip, or to manually actuate the identified safety-related equipment. DCD Section 7.7.1.11 (Ref. 2) provides a description of the DAS.
APPLICABLE SAFETY ANALYSES	The DAS manual controls are required to provide a diverse capability to manually trip the reactor and actuate the specified safety-related equipment, based on risk importance in the AP1000 PRA. The DAS manual controls are not credited for mitigating accidents in the DCD Chapter 15 safety analyses. The AP1000 PRA, Appendix A, provides additional information, including the thermal and hydraulic analyses of success sequences used in the PRA. The DAS manual controls satisfy Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	The DAS LCO provides the requirements for the OPERABILITY of the DAS manual trip and actuation controls necessary to place the reactor in a shutdown condition and to remove decay heat in the event that the PMS automatic actuation and manual controls are inoperable.
APPLICABILITY	The DAS manual controls are required to be OPERABLE in the MODES specified in Table 3.3.5-1. The manual DAS reactor trip control is required to be operable in MODES 1 and 2 to mitigate the effects of an ATWS event occurring during power operation. The other manual DAS actuation controls are required to be available in the plant MODES specified, based on the need

(continued)

BASES

APPLICABILITY (continued)

for operator action to actuate the specified components during events that may occur in these various plant conditions, as identified in the AP1000 PRA.

ACTIONS

A.1

Condition A applies when one or more DAS manual controls are inoperable.

The Required Action A.1 to restore the inoperable DAS manual control(s) to OPERABLE status within 30 days is reasonable because the DAS is a separate and diverse non-safety backup system for the manual reactor trip and manual safety-related equipment actuation controls. The 30-day Completion Time allows sufficient time to repair an inoperable manual DAS control but ensures the control is repaired to provide backup protection.

B.1 and B.2

Condition B applies when Required Action A cannot be completed for the DAS manual reactor trip control within the required completion time of 30 days.

Required Action B.1 requires SR 3.3.1.5, "Perform TADOT" for the reactor trip breakers, is to be performed once per 31 days, instead on once every 92 days. The predominant failure requiring the DAS manual reactor trip control is common mode failure of the reactor trip breakers. This change in surveillance frequency for testing the reactor trip breakers increases the likelihood that a common mode failure of the reactor trip breakers would be detected while the DAS manual reactor trip control is inoperable. This reduces the likelihood that a diverse manual reactor trip is required. It is not required to perform a TADOT for the manual actuation control. The manual reactor trip control is very simple, highly reliable, and does not use software in the circuitry.

Action B.2 requires that the inoperable DAS manual reactor trip control be restored to OPERABLE status prior to entering MODE 2 following any plant shutdown to MODE 5 while the control is inoperable. This ACTION is provided to ensure that all DAS manual controls are restored to OPERABLE status following the next plant shutdown.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

Condition C applies when Required Action A cannot be completed for any DAS manual actuation control (other than reactor trip) within the required completion time of 30 days.

Required Action C.1 requires SR 3.3.2.2, "Perform ACTUATION LOGIC TEST," to be performed once per 31 days, instead on once every 92 days. The predominant failure requiring the DAS manual reactor trip control is common mode failure of the PMS actuation logic software or hardware. This change in surveillance frequency for actuation logic testing increases the likelihood that a common mode failure of the PMS actuation logic from either cause would be detected while any DAS manual actuation control is inoperable. This reduces the likelihood that a diverse component actuation is required. It is not required to perform a TADOT for the manual actuation control device since the manual actuation control devices are very simple and highly reliable.

Action C.2 requires that the inoperable DAS manual actuation control(s) be restored to OPERABLE status prior to entering MODE 2 following any plant shutdown to MODE 5 while the control is inoperable. This ACTION is provided to ensure that all DAS manual controls are restored to OPERABLE status following the next plant shutdown.

D.1 and D.2

Condition D is entered if the Required Action associated with Condition B or C is not met within the required Completion Time.

Required Actions D.1 and D.2 ensure that the plant is placed in a condition where the probability and consequences of an event are minimized. The allowed Completion Times are reasonable based on plant operating experience, for reaching the required plant conditions from full power conditions in an orderly manner, without challenging plant systems.

(continued)

RAI Number 440.108

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT of the DAS manual trip and actuation controls for the specified safety-related equipment. This TADOT is performed every 24 months.

The Frequency is based on the known reliability of the DAS functions and has been shown to be acceptable through operating experience.

The SR is modified by a Note that excludes verification of the setpoints from the TADOT. The functions have no setpoints associated with them.

REFERENCES

1. WCAP-15985, "AP1000 Implementation of the Regulatory Treatment of Nonsafety-Related Systems Process," November 2002.
2. DCD, Section 7.7.1.11.

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.001

Question:

A. (Section 16.1) The AP600 TSs were modeled after Revision 1 to NUREG-1431, "Standard Technical Specifications [STS] Westinghouse Plants," and the AP1000 TSs closely resemble the AP600 TSs. Many improvements (referred to as TS Task Force improvements or TSTFs) to NUREG-1431 have been made since Revision 1 was issued in 1995. These improvements have been incorporated into Revision 2 of NUREG-1431 which was issued in June 2001. (In addition, more TSTFs have been approved since the issuance of Revision 2.) Have you considered referencing Revision 2 of the STS for the AP1000 or incorporating each TSTF that was approved since the issuance of Revision 1? Please provide an explanation for the disposition of each TSTF, whether incorporated or not, noting the reason for any differences from Revision 2, as currently updated with approved TSTFs.

B. (Section 16.1) Are there any AP1000 systems not covered by TSs that meet the criteria of 10 CFR 50.36(c)(2)(ii), i.e., have you performed an AP1000-specific review of systems that should be covered by TSs? Identify all non-TS systems that contribute to risk reduction (as determined by the PRA) and state why these systems do not satisfy 10 CFR 50.36(c)(2)(ii)(A), (B), (C), and (D). For any non-TS system that is found to meet any of the four criteria, propose an associated TS LCO or justify not including the system in TSs.

Westinghouse Response:

A. The AP1000 TSs have been updated to incorporate the technical requirements of NUREG-1431, Rev. 2. The update generally includes a large number of specific editorial revisions to the AP1000 TSs and Bases text to make it consistent with the STS. In general, the goal is to have the AP1000 TSs and Bases use the same wording as the corresponding STS Rev. 2 TS and Bases, except where technical differences for the AP1000 result in the need for a difference in the TSs or Bases. This approach was also followed for the AP600, which were patterned after the STS, Rev. 1.

The AP1000 TS update to STS Rev. 2 does NOT include non-technical format changes, such as font, spacing, pagination, etc. The intent of the update was not to completely revise all TS pages, but only those with some technical difference required to be consistent with the STS, Rev. 2. No global changes were made for repagination or other changes that were not considered to be technically based. Therefore, only the portions of the pages with the change bar in the margin of the TS or Bases pages have been revised. The update does include identified typographical errors. In some cases, where a specific change may have been requested in an RAI for clarification of a TS or Bases, the update includes some format changes such as a change in the placement of notes where this provided a technical clarification in understanding the TS.

Many of the RAIs, particularly for the 630 series RAIs identified specific requests for changes to be consistent with the STS, Rev. 2, and these RAIs individually reference this RAI in their response.

The AP1000 TS update to STS, Rev. 2 does NOT include incorporation of any TS Task Force improvements for differences or improvements beyond Rev. 2 of the STS. The AP1000 DCD includes a COL action to update TSs to the current revision of the STS at the time of plant licensing.

B. See the response to RAI 100.003 on the regulatory treatment for nonsafety-related systems (RTNSS) for a discussion of the evaluation of AP1000 systems not covered by TSs. As a result of the RTNSS process for AP1000, the diverse Actuation System (DAS) manual actuation controls were identified to satisfy the risk reduction criteria of 10 CFR 50.36(c)(2)(ii), Criterion (D). Therefore, a new TS 3.3.5 was added for the specified DAS manual actuation controls.

AP1000 structures, systems, and components (SSCs) that meet any of the four screening criteria of 10 CFR 50.36(c)(2)(ii) have an associated TS in the AP1000 TSs. There are no AP1000 systems that meet the criteria of 10 CFR 50.36(c)(2)(ii) that are not covered by a TS.

The process for developing TSs for the AP600 and AP1000 was to apply the four screening criteria of 10 CFR 50.36(c)(2)(ii) to the plant systems. Where SSCs satisfy any of the screening criteria, a TS was created for that SSC. As discussed in the response to Item A, each AP1000 TS is modeled after the corresponding TS from the STS, if a corresponding TS existed in the STS. Where new TSs were developed, the most appropriate STS TSs, or portions of TSs, were used as models. As part of the development of the TS Bases, the last paragraph in the Applicable Safety Analyses section of the Bases for each AP1000 TS identifies the applicable screening criteria that identified the requirement for development of the TS.

Therefore, an AP1000 TS has been developed for any SSCs that satisfies the criteria 10 CFR 50.36(c)(2)(ii), including Criterion (D) which includes SSCs determined to be significant to safety based on the AP1000 PRA.

Design Control Document (DCD) Revision:

See the attached AP1000 TS and Bases that have been updated to be consistent with Rev. 2 of NUREG-1431.

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.002

Question:

(Section 16.1) Several mostly global editorial enhancements and corrections have been incorporated into Revision 2 of the STS and should be adopted in the AP1000 TSs. See STS Revision 2 for additional details. For instance:

A. Page numbering in the TSs and the Bases was changed to a specification basis, rather than a section basis,

B. References to the Nuclear Regulatory Commission (NRC) Policy Statement criteria in the TS Bases Applicable Safety Analyses discussions should be replaced by references to 10 CFR 50.36(c)(2)(ii) criteria. Also, the Bases of every limiting condition of operation (LCO) in Sections 3.1 through 3.9 must state which of the 4 criteria apply to the LCO; if none, then include an explanation why the LCO is otherwise specified,

C. The Bases Control Program in TS Section 5.0 should be revised to reflect the revised 10 CFR 50.59, which no longer uses the term 'unreviewed safety question.'

D. The convention for noting continuation of a subsection to the next page and from the prvious page, both in the TSs and the Bases, was simplified and made easier to follow,

E. Format for Notes in the TSs was changed to stand out better and be more consistent.

F. Example 1.3-3 illustrates the use of an LCO restoration overall Completion Time for Action tables that otherwise could logically be entered and never exited. This type of Completion Time is not implemented in all cases (in TS Sections 3.1 - 3.9) where it should be (for example, TS 3.7.10). Identify those LCOs for which this restriction could be applied and modify them accordingly. In each such case explain why this limitation is not adopted.

Westinghouse Response:

As discussed in the response to RAI 630.001, the AP1000 TSs were updated to be technically consistent with the requirements of Rev. 2 to NUREG-1431.

A. The TS pagination is a format change that was not included in the technical update to Rev. 2 of the STS. Page numbering and other format changes are a significant effort and are not included in the AP1000 TS update at this time. The Rev. 2 editorial enhancements, and any other administrative or format enhancements in the current revision of the STS will be incorporated when there is a complete technical and editorial update to the AP1000 TSs in the future.

B. The AP1000 TS update to Rev. 2 of the STS includes correcting the Bases to correctly reference the screening criteria of 10 CFR 50.36(c)(2)(ii) instead of the NRC policy statement screening criteria. The update also includes confirming that the applicable screening criteria is identified in the last paragraph of the Applicable Safety Analyses section of the Bases for each TS. Some of the 630 series RAIs included specific comments that the screening criteria was not identified for a specific TS, or that the NRC policy statement criteria were incorrectly referenced. The global review of the AP1000 TSs corrected these identified errors.

C. The Bases Control Program in TS Section 5.5.7 was revised to be consistent with Rev. 2 of the STS to reference 10 CFR 50.59, and to remove the term "unreviewed safety question."

D. As discussed in the response to Item A, format changes are not included in this update to the AP1000 TS. Since the convention for noting continuation of a subsection to the next page is a format change, it has NOT been included in this AP1000 update to Rev. 2 of the STS.

E. As discussed in the response to Item A, format changes are not included in this update to the AP1000 TS. Reformatting of notes has NOT been included in this AP1000 update to Rev. 2 of the STS. Where a specific RAI may have identified the need to move a note's location and the change provided improved technical clarity or understanding, a change to a note has been made. But no changes to the formatting of the notes has been included in this AP1000 update.

F. The AP1000 TSs have been developed to be consistent with the STS. Based on the response to RAI 630.001, the AP1000 TS are updated to be consistent with STS, Rev. 2

The Completion Time format specified in Example 1.3-3 is implemented in the following four TSs in the STS, Rev. 2:

3.6.6	Containment Spray
3.7.5	AFW System Trains
3.8.1	AC Sources - Operating
3.8.9	Distribution Systems - Operating

Because of the AP1000 design differences, there is no safety-related containment spray system, the AFW does not provide the safety-related heat removal function, and AC power is not safety-related. Therefore, these three specifications do not exist for AP1000. AP1000 TS 3.8.5 is modeled after STS TS 3.8.9 and includes an equivalent Completion Time to STS TS 3.8.9, which is consistent with the format in Example 1.3-3. This is the only required application of the Example 1.3-3 Completion Time format applicable for AP1000, consistent with the update to STS, Rev. 2.

However, based on recent progress in development of the STS, the application of this Completion Time format to AP1000 TS 3.8.5 is expected to be deleted from AP1000 in a future update. As stated in the response to RAO 630.001, Item A, the update to STS, Rev. 2 does not include more recent TS Task Force (TSTF) improvements. However, it is recognized that a TSTF exists with the purpose of deleting this type of Completion Time from NUREG-1431. The attached copy of TSTF-439, Rev. 1, shows that for NUREG-1431, Example 1.3-3 is being deleted, along with the associated Bases discussion. The TSTF specifically identifies deletion of this Completion Time in the four STS TSs listed above, as well. Therefore, this applies to the single AP1000 application as well, although it is retained for now, to be consistent with Rev. 2 of the STS.

Therefore, since this type of Completion Time will no longer be used in the STS, it is not required to conduct an evaluation of the Completion Times in TS Sections 3.1 to 3.9 to identify Actions that could logically be entered and never exited.

Design Control Document (DCD) Revision:

<u>Bases Control Program, TS Section 5.5.7</u>

b. Licensees may make changes to Bases without prior NRC approval provided the changes does not **require** ~~involve~~ either of the following:

   1. A~~a~~ change in the TS incorporated in the license; or

   2. A~~a~~ change to the updated FSAR or Bases that **requires NRC approval pursuant to** ~~involves an unreviewed safety question as defined in~~ 10 CFR 50.59.

PRA Revision:

None

5.5 Programs and Manuals (continued)

5.5.7 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

1. A change in the TS incorporated in the license; or

2. A change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

d. Proposed changes that meet the criteria of (b) above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5.8 Safety Function Determination Program (SFDP)

This program ensure loss of safety function is detected and appropriate action taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the supported system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirement of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

(continued)

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.003

Question:

(Section 16.1, TS Section 1.1) The AP1000 definition of Dose Equivalent I-131 differs from that of the STSs and the AP600 TSs; and the definition of Dose Equivalent Xe-133 differs from that of the AP600 TSs (this definition is not contained in the STSs). Please explain the differences and why they are acceptable.

Westinghouse Response:

The definition of "Dose Equivalent I-131" for the AP1000 differs from that used in the AP600 Technical Specifications in that the list of iodine isotopes was extended to include I-130 and the basis for calculating the dose equivalent was changed from thyroid dose to committed effective dose equivalent (CEDE). The inclusion of I-130 in the spectrum of iodine isotopes is based on a review of the source term and the resulting determination that the contribution to the accident dose calculations, while small, could be considered to have significance.

The use of CEDE dose conversion factors as the basis for determining dose equivalence in place of the using thyroid dose conversion factors was implemented to make the Technical Specifications consistent with the accident dose analysis methodology which no longer includes a determination of thyroid and whole body doses (see Regulatory Guide 1.183) but instead reports the doses as total effective dose equivalent (TEDE) which is obtained by combining the CEDE dose and the acute dose from direct radiation. This is the same dose methodology that was used in the AP600 analyses but the AP600 Technical Specification definition for Dose Equivalent I-131 does not reflect it.

The definition of "Dose Equivalent Xe-133" for the AP1000 differs from that used in the AP600 Technical Specifications in that the list of noble gases was extended to include Xe-135m and the basis for calculating the dose equivalent was changed from the values provided in Table 2.3 of EPA Federal Guidance Report No. 11 to those provided in Table III.1 of EPA Federal Guidance Report No. 12. The inclusion of Xe-135m in the spectrum of nuclides corrects its unintended omission from the list used for the AP600. Contributions to accident doses from noble gas releases include consideration of Xe-135m in both the AP600 and the AP1000 analyses.

The change in source document for the dose conversion factors (DCFs) is reflective of the change made in the accident dose analyses to use DCFs from EPA Federal Guidance Report No. 12 consistent with the guidance provided by the NRC in Regulatory Guide 1.183. It was considered desirable to have the definition for Dose Equivalent Xe-133 use DCFs that are consistent with the radiological consequences analyses.

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.004

Question:

(Section 16.1, TS Sections 1.2, 1.3, and 1.4) The last paragraph of Example 1.3-6 of the AP1000 TS Section 1.3 and in Section 16.1, page 1.3-11, is incorrectly placed after the title for Example 1.3-7. Also, each example in Sections 1.2, 1.3, and 1.4 should start on a new page, consistent with the STS format. Please revise the DCD accordingly.

Westinghouse Response:

The last paragraph of Example 1.3-6 of the AP1000 TS Section 1.3 (Section 16.1, page 1.3-11) will be revised as indicated in the attachment.

The other requested changes are format changes. As discussed in RAI 630.001, the AP1000 Technical Specification update to STS Revision 2 include technical changes but will not include formatting changes.

Design Control Document (DCD) Revision:

See attached AP1000 Tech Spec markup.

PRA Revision:

None

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-6 (continued)

Required Action A.1 must be complete within the first 8 hour interval. If Required Action A.1 is followed, and the Required Action is not met within the Completion Time (plus the extension allowed by SR 3.0.2), Condition B is entered. If Required Action A.2 is followed and the Completion Time of 8 hours is not met, Condition B is entered.

~~EXAMPLE 1.3-7~~

If after entry into Condition B, Required Action A.1 or A.2 is met, Condition B is exited and operation may then continue in Condition A.

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated. AND A.2 Restore subsystem to OPERABLE status.	1 hour AND Once per 8 hours thereafter 72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-6 (continued)

Required Action A.1 must be complete within the first 8 hour interval. If Required Action A.1 is followed, and the Required Action is not met within the Completion Time (plus the extension allowed by SR 3.0.2), Condition B is entered. If Required Action A.2 is followed and the Completion Time of 8 hours is not met, Condition B is entered.

If after entry into Condition B, Required Action A.1 or A.2 is met, Condition B is exited and operation may then continue in Condition A.

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Restore subsystem to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

(continued)

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.005

Question:

(Section 16.1, TS Section 2.1 Bases) The safety limits discussion in the Bases for the reactor coolant system (RCS) Pressure Safety Limit in the AP600 and the STS Revision 2 Bases, includes bracketed information regarding the pressure allowances for the RCS piping, as well as the pressure vessel allowances of the American Society of Mechanical Engineers (ASME) Code, Section III. However, the AP1000 discussion only refers to the RCS pressure "boundary" pressure limit without separately addressing the vessel and the piping pressure limits, and omits the bracketed information. Provide the rationale for this difference or restore the omitted information consistent with the AP1000 design.

Westinghouse Response:

The pressure safety limit for the AP1000 reactor coolant pressure boundary (RCPB) components, which includes the reactor pressure vessel, piping, valves and fittings, is governed by the ASME Code, Section III. The maximum transient pressure allowed under the ASME Code, Section III, is 110% of design pressure. The AP1000 TS B2.1.2 SAFETY LIMIT will be modified, as indicated below, to be consistent with the STS, Rev. 2 wording.

Design Control Document (DCD) Revision:

SAFETY LIMITS The maximum transient pressure allowed in the RCS pressure ~~boundary~~**vessel, piping, valves, and fittings** under the ASME Code, Section III, is 110% of design pressure; therefore, the SL on maximum allowable RCS pressure is 2733.5 psig.

PRA Revision:

None

BASES

APPLICABLE SAFETY ANALYSES (continued)

The RCS pressurizer safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10%, as specified in Section III of the ASME Code for Nuclear Power Plant Components (Ref. 2). The transient that establishes the required relief capacity, and hence valve size requirements and lift settings, is a complete loss of external load with loss of feedwater flow, without a direct reactor trip. During the transient, no control actions are assumed except that the safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valve settings.

The Reactor Trip System setpoints (Ref. 5), together with the settings of the MSSVs, provide pressure protection for normal operation and AOOs. The reactor high pressurizer pressure trip setpoint is specifically set to provide protection against overpressurization (Ref. 5). The safety analyses for both the high pressurizer pressure trip and the RCS pressurizer safety valves are performed using conservative assumptions relative to pressure control devices.

More specifically, no credit is taken for operation of the following:

a. RCS depressurization valves;
b. Steam line relief valves (SG PORVs);
c. Turbine Bypass System;
d. Reactor Control System;
e. Pressurizer Level Control System; or
f. Pressurizer spray.

SAFETY LIMITS

The maximum transient pressure allowed in the RCS pressure vessel, piping, valves, and fittings under the ASME Code, Section III, is 110% of design pressure; therefore, the SL on maximum allowable RCS pressure is 2733.5 psig.

(continued)

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.006

Question:

(Section 16.1, TS LCO 3.0.8) LCO 3.0.8 and supporting Bases refer to the Safety System Shutdown Monitoring Tree parameters. The Bases also refer to the Shutdown Emergency Response Guidelines. Where are these found? Also, provide a specific example that demonstrates how LCO 3.0.8 works. Consider adding such an example to TS Section 1.3, or explain it in the Bases.

Westinghouse Response:

LCO 3.0.8 applies in Modes 5 and 6, and is equivalent to LCO 3.0.3 that only applies in Modes 1, 2, 3 and 4. LCO 3.0.8 was incorporated in the AP600 Technical Specifications as a result of the staff's request to address shutdown modes in the AP600 Technical Specifications.

LCO 3.0.8 provides actions for Conditions not covered in other Specifications for Modes 5 and 6. LCO 3.0.8 directs the operators to monitor the safety system shutdown status trees that are part of the Shutdown Emergency Response Guidelines (ERGs), and were incorporated in the AP600 ERGs.

The AP1000 references the AP600 ERGs that contain the Shutdown Emergency Response Guidelines and Shutdown Safety Status Trees. The AP600 ERGs were issued in the Westinghouse letter DCP/NRC1385 to T.R. Quay, dated June 24, 1998. Refer to the response to RAI 440.109 for a discussion of the applicability of the AP600 ERG to the AP1000.

The examples provided in Technical Specification section 1.3 for LCO 3.0.3 are applicable to LCO 3.0.8. The Bases for 3.0.8 was revised as shown below to show how LCO 3.0.8 would be applied for a specific example during shutdown conditions.

Design Control Document (DCD) Revision:

The following paragraph will be added at the end of the Bases for LCO 3.0.8.

> As an example of the application of LCO 3.0.8, see column 2 of Table B 3.0-1, Passive Systems Shutdown MODE Matrix, for the core makeup tank. This example assumes that the plant is initially in MODE 5 with the RCS pressure boundary intact. In this plant condition, LCO 3.5.3 requires one core makeup tank to be OPERABLE. The table shows the required end state established by the Required Actions of TS 3.5.3 in the event that the core makeup tank cannot be restored to OPERABLE status.

For this initial plant shutdown condition with no OPERABLE core makeup tanks, four conditions are identified in TS 3.5.3, with associated Required Actions and Completion Times. If Conditions A, B, and C cannot be completed within the required Completion Times, then Condition D requires immediately initiating action to place the plant in MODE 5 with the RCS pressure boundary open, and with pressurizer level greater than 20 percent.

LCO 3.0.8 would apply if actions could not immediately be initiated to open the RCS pressure boundary. In this situation, in parallel with the TS 3.5.3 actions to continue to open the RCS pressure boundary, LCO 3.0.8 requires the operators to take actions to restore one core makeup tank to OPERABLE status, and to monitor the Safety System Shutdown Monitoring Trees.

The Shutdown Status Trees monitor seven key RCS parameters and direct the operators to one of six shutdown ERGs in the event that any of the parameters are outside of allowable limits. The shutdown ERGs identify actions to be taken by the operators to satisfy the critical safety functions for the plant in the shutdown condition, using plant equipment available in this shutdown condition. LCO 3.0.8 monitoring would continue to be required until one core makeup tank is restored to OPERABLE status or the Required Actions for Condition D can be satisfied. In this case, once the RCS pressure boundary is open as required by Condition D, LCO 3.0.8 would be exited.

PRA Revision:

None

In MODES 5 and 6, LCO 3.0.8 provides actions for Conditions not covered in other Specifications and for multiple concurrent Conditions for which conflicting actions are specified.

As an example of the application of LCO 3.0.8, see column 2 of Table B 3.0-1, Passive Systems Shutdown MODE Matrix, for the core makeup tank. This example assumes that the plant is initially in MODE 5 with the RCS pressure boundary intact. In this plant condition, LCO 3.5.3 requires one core makeup tank to be OPERABLE. The table shows the required end state established by the Required Actions of TS 3.5.3 in the event that the core makeup tank cannot be restored to OPERABLE status.

For this initial plant shutdown condition with no OPERABLE core makeup tanks, four conditions are identified in TS 3.5.3, with associated Required Actions and Completion Times. If Conditions A, B, and C cannot be completed within the required Completion Times, then Condition D requires immediately initiating action to place the plant in MODE 5 with the RCS pressure boundary open, and with pressurizer level greater than 20 percent.

LCO 3.0.8 would apply if actions could not immediately be initiated to open the RCS pressure boundary. In this situation, in parallel with the TS 3.5.3 actions to continue to open the RCS pressure boundary, LCO 3.0.8 requires the operators to take actions to restore one core makeup tank to OPERABLE status, and to monitor the Safety System Shutdown Monitoring Trees.

The Shutdown Status Trees monitor seven key RCS parameters and direct the operators to one of six shutdown ERGs in the event that any of the parameters are outside of allowable limits. The shutdown ERGs identify actions to be taken by the operators to satisfy the critical safety functions for the plant in the shutdown condition, using plant equipment available in this shutdown condition. LCO 3.0.8 monitoring would continue to be required until one core makeup tank is restored to OPERABLE status or the Required Actions for Condition D can be satisfied. In this case, once the RCS pressure boundary is open as required by Condition D, LCO 3.0.8 would be exited.

RAI Number: 630.007

Question:

(Section 16.1, TS Section 3.0) The Passive System Shutdown MODE Matrix lacks the designation of "Table B 3.0-1." Please revise the DCD accordingly.

Westinghouse Response:

Table B 3.0-1 designation will be added to the Passive System Shutdown MODE Matrix in the AP1000 T.S. as indicated below. In addition, the Table B 3.0-1 will be moved to end of the section after LCO 3.0.8. NOTE: These changes are also captured in the AP1000 Technical Specification changes to update to STS Revision 2, as discussed in RAI 630.001.

Design Control Document (DCD) Revision:

Table B 3.0-1 (Page 1 of 1)
Passive Systems Shutdown MODE Matrix

LCO Applicability	Automatic Depressurization System	Core Makeup Tank	Passive RHR	IRWST	Containment	Containment Cooling[(1)]
MODE 5 RCS pressure boundary intact	9 of 10 paths OPERABLE All paths closed LCO 3.4.13	One CMT OPERABLE LCO 3.5.3	System OPERABLE LCO 3.5.5	One injection flow path and one recirculation sump flow path OPERABLE LCO 3.5.7	Closure capability LCO 3.6 8	Three water flow paths OPERABLE LCO 3.6.7
Required End State	MODE 5 RCS pressure boundary open, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary open, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary open, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level
MODE 5 RCS pressure boundary open or pressurizer level <20%	Stages 1, 2, and 3 open 2 stage 4 valves OPERABLE LCO 3.4.14	None	None	One injection flow path and one recirculation sump flow path OPERABLE LCO 3.5.7	Closure capability LCO 3.6 8	Three water flow paths OPERABLE LCO 3.6.7
Required End State	MODE 5 RCS pressure boundary open, ≥ 20% pressurizer level			MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level
MODE 6 Upper internals in place	Stages 1, 2, and 3 open 2 stage 4 valves OPERABLE LCO 3.4.14	None	None	One injection flow path and one recirculation sump flow path OPERABLE LCO 3.5.8	Closure capability LCO 3.6.8	Three water flow paths OPERABLE LCO 3.6 7
Required End State	MODE 6 Upper internals removed			MODE 6 Refueling cavity full	MODE 6 Refueling cavity full	MODE 6 Refueling cavity full
MODE 6 Upper internals removed	None	None	None	One injection flow path and one recirc-ulation sump flow path OPERABLE LCO 3.5.8	Closure capability LCO 3.6.8	Three water flow paths OPERABLE LCO 3.6.7
Required End State				MODE 6 Refueling cavity full	MODE 6 Refueling cavity full	MODE 6 Refueling cavity full

(1) Containment cooling via PCS is not required when core decay heat <9 MWt.

PRA Revision:

None

Table B 3.0-1 (page 1 of 1)
Passive Systems Shutdown MODE Matrix

LCO Applicability	Automatic Depressurization System	Core Makeup Tank	Passive RHR	IRWST	Containment	Containment Cooling[1]
MODE 5 RCS pressure boundary intact	9 of 10 paths OPERABLE All paths closed LCO 3 4.13	One CMT OPERABLE LCO 3.5.3	System OPERABLE LCO 3 5.5	One injection flow path and one recirculation sump flow path OPERABLE LCO 3.5.7	Closure capability LCO 3 6.8	Three water flow paths OPERABLE LCO 3.6 7
Required End State	MODE 5 RCS pressure boundary open, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary open, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary open, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level
MODE 5 RCS pressure boundary open or pressurizer level <20%	Stages 1, 2, and 3 open 2 stage 4 valves OPERABLE LCO 3.4.14	None	None	One injection flow path and one recirculation sump flow path OPERABLE LCO 3.5.7	Closure capability LCO 3 6.8	Three water flow paths OPERABLE LCO 3 6.7
Required End State	MODE 5 RCS pressure boundary open, ≥ 20% pressurizer level			MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level	MODE 5 RCS pressure boundary intact, ≥ 20% pressurizer level
MODE 6 Upper internals in place	Stages 1, 2, and 3 open 2 stage 4 valves OPERABLE LCO 3.4.14	None	None	One injection flow path and one recirculation sump flow path OPERABLE LCO 3.5.8	Closure capability LCO 3.6 8	Three water flow paths OPERABLE LCO 3 6.7
Required End State	MODE 6 Upper internals removed			MODE 6 Refueling cavity full	MODE 6 Refueling cavity full	MODE 6 Refueling cavity full
MODE 6 Upper internals removed	None	None	None	One injection flow path and one recirculation sump flow path OPERABLE LCO 3.5 8	Closure capability LCO 3 6.8	Three water flow paths OPERABLE LCO 3 6.7
Required End State				MODE 6 Refueling cavity full	MODE 6 Refueling cavity full	MODE 6 Refueling cavity full

(1) Containment cooling via PCS is not required when core decay heat <9 MWt.

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.008

Question:

(Section 16.1, TS Section 3.1) Acceptance of TS Section 3.1 requires resolution of the AP1000 RAIs 440.100 and 440.101. Please resolve these issues and revise the DCD/TSs accordingly.

NOTE: AP1000 RAIs 440.100 and 440.101 were issued on September 18, 2002 (ADAMS Accession No. ML022610042).

Westinghouse Response:

The AP1000 Technical Specification will be revised as indicated below. These changes are a result of resolution of RAIs 440.100 and 440.101.

Design Control Document (DCD) Revision:

DCD Chapter 16.1, Technical Specification 3.1.4, SR 3.1.4.3, pg 3.1-10:

Verify rod drop time of each rod, from the fully withdrawn position, is $\leq$ [~~2.7~~**2.47**] seconds from the beginning of decay of stationary gripper coil voltage to dashpot entry, with:

a. $T_{avg} \geq 500°F$, and

b. All reactor coolant pumps operating.

DCD Chapter 16.1, Technical Specification 3.2.1: See attached changes to TS 3.2.1, revised to be consistent with TS 3.2.1B of NUREG-1431, Rev. 2. These changes are also addressed in RAI 630.001, which provides the AP1000 TS changes to be consistent with STS, Rev. 2.

PRA Revision:

None

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.4.2	Verify rod freedom of movement (trippability) by moving each rod not fully inserted in the core $\geq$ 10 steps in either direction.	92 days
SR 3.1.4.3	Verify rod drop time of each rod, from the fully withdrawn position, is $\leq$ [2.47] seconds from the beginning of decay of stationary gripper coil voltage to dashpot entry, with: a. $T_{avg} \geq 500°F$, and b. All reactor coolant pumps operating.	Prior to reactor criticality after each removal of the reactor head

3.2 POWER DISTRIBUTION LIMITS

3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$) (F_Q Methodology)

LCO 3.2.1 $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1 with On-line Power Distribution Monitoring System (OPDMS) inoperable.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
-----------NOTE----------- Required Action A.4 shall be completed whenever this Condition is entered. -------------------------		
A. $F_Q^C(Z)$ not within limit.	A.1 Reduce THERMAL POWER $\geq$ 1% RTP for each 1% $F_Q^C(Z)$ exceeds limit.	15 minutes after each $F_Q^C(Z)$ determination
	AND	
	A.2 Reduce Power Range Neutron Flux High trip setpoints $\geq$ 1% for each 1% $F_Q^C(Z)$ exceeds limit.	72 hours after each $F_Q^C(Z)$ determination
	AND	
	A.3 Reduce Overpower ΔT trip setpoints $\geq$ 1% for each 1% $F_Q^C(Z)$ exceeds limit.	72 hours after each $F_Q^C(Z)$ determination
	AND	

	A.4 Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the limit of Required Action A.1

(continued)

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
----------NOTE----------- Required Action B.4 shall be completed whenever this Condition is entered. ------------------------		
B. $F_Q^W(Z)$ not within limits.	B.1 Reduce AFD limits $\geq$ 1% for each 1% $F_Q^W(Z)$ exceeds limit.	4 hours
	AND	
	B.2 Reduce Power Range Neutron Flux - High trip setpoints $\geq$ 1% for each 1% that the maximum allowable power of the AFD limits is reduced.	72 hours
	AND	
	B.3 Reduce Overpower ΔT trip setpoints $\geq$ 1% for each 1% that the maximum allowable power of the AFD limits is reduced.	72 hours
	AND	
	B.4 Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the maximum allowable power of the AFD limits

C. Required Action and associated Completion Time not met.	C.1 Be in MODE 2.	6 hours

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.009

Question:

(Section 16.1, TS 3.1.1 Bases) The Bases for STS TS 3.1.1 Actions ends with the following paragraph:

"In determining the boration flow rate, the time in core life must be considered. For instance, the most difficult time in core life to increase the RCS boron concentration is at the beginning of [the] cycle, when the boron concentration may approach or exceed 2000 ppm. Assuming that a value of [1]% Δk/k must be recovered and a boration flow rate is [ ] gpm, it is possible to increase the boron concentration of the RCS by 100 ppm in approximately 35 minutes. If a boron worth of 10 pcm/ppm is assumed, this combination of parameters will increase the SDM [shutdown margin] by [1]% Δk/k. These boration parameters of [ ] gpm and [ ] ppm represent typical values and are provided for the purpose of offering a specific example."

The corresponding AP1000 Bases omits everything after the second sentence, which is modified by replacing "may exceed 2000 ppm" by "is highest." Please provide the rationale for these differences or adopt the STS discussion.

Westinghouse Response:

With the AP1000 low boron core design, the highest boron concentration, during power operation, is much less than 2000 ppm, thus the reason the TS was modified to replace "may exceed 2000 ppm" with "is highest".

The AP1000 TS 3.1.1 Bases will be revised as indicated below, to be consistent with the STS wording.

Design Control Document (DCD) Revision:

From DCD Chapter 16, TS 3.1.1 Bases, pg. B 3.1-5:

ACTIONS A.1 (continued)

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a concentrated solution. The operator should begin boration with the best source available for the plant conditions.

In determining the boration flow rate, the time in core life must be considered. For instance, the most difficult time in core life to increase the RCS boron concentration is at the beginning of cycle when the boron concentration is highest. **Assuming that a value of (1.6)% Δk/k must be recovered and a boration flow rate is (100) gpm, it is possible to increase the boron concentration of the RCS by 112 ppm in approximately 29 minutes. If a boron worth of 9 pcm/ppm is assumed, this combination of parameters will increase the SDM (shutdown margin) by (1.6)% Δk/k. These boration parameters of (100) gpm and (9) ppm represent typical values and are provided for the purpose of offering a specific example."**

PRA Revision:

None

RAI Number 630.009

BASES

ACTIONS

A.1 (continued)

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a concentrated solution. The operator should begin boration with the best source available for the plant conditions.

In determining the boration flow rate, the time in core life must be considered. For instance, the most difficult time in core life to increase the RCS boron concentration is at the beginning of cycle when the boron concentration is highest. Assuming that a value of [1.6]% $\Delta k/k$ must be recovered and a boration flow rate is [100] gpm, it is possible to increase the boron concentration of the RCS by 112 ppm in approximately 29 minutes. If a boron worth of 9 pcm/ppm is assumed, this combination of parameters will increase the SDM [shutdown margin] by [1.6]% $\Delta k/k$. These boration parameters of [100] gpm and [9] ppm represent typical values and are provided for the purpose of offering a specific example."

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

In MODES 1 and 2, SDM is verified by observing that the requirements of LCO 3.1.5 and LCO 3.1.6 are met. In the event that a rod is known to be untrippable, however, SDM verification must account for the worth of the untrippable rod as well as another rod of maximum worth.

In MODES 3, 4, and 5, the SDM is verified by performing a reactivity balance calculation, considering the listed reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal Temperature Coefficient (ITC).

(continued)

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.010

Question:

(Section 16.1, TS Surveillance Requirement (SR) 3.1.2.1 Bases) The Bases for AP1000 SR 3.1.2.1 does not discuss the additional requirement given in the second sentence of the Note to this SR. The corresponding STS SR 3.1.2.1 Note does not contain this sentence. Please revise the Bases to explain the reason for and acceptability of this additional requirement.

Westinghouse Response:

SR 3.1.2.1 is being modified to be consistent with STS, Rev. 2 as indicated below.

NOTE: This change is also captured in the AP1000 Technical Specification changes to update to STS Revision 2 (see RAI 630.001).

Design Control Document (DCD) Revision:

	SURVEILLANCE	FREQUENCY
SR 3.1.2.1	------------------NOTE----------------- ~~The predicted core reactivity shall be normalized to the measured core reactivity prior to exceeding a fuel burnup of 60 effective full power days (EFPDs) after each fuel loading. If the normalized boron letdown curve is higher than the predicted boron letdown curve, then adjust, as appropriate, all relevant operating curves and tables affected by a boron concentration difference from design.~~ **The predicted reactivity values may be adjusted (normalized) to correspond to the measured core reactivity prior to exceeding a fuel burnup of 60 effective full power days (EFPD) after each fuel loading.** ------------------------------------ Verify measured core reactivity is within ±1% Δk/k of predicted values.	~~Once p~~Prior to entering MODE 1 after each refueling <u>AND</u> -----NOTE------ Only required after 60 EFPD -------------- 31 EFPD thereafter

PRA Revision:

None

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.2.1	------------------NOTE------------------ The predicted reactivity values may be adjusted (normalized) to correspond to the measured core reactivity prior to exceeding a fuel burnup of 60 effective full power days (EFPD) after each fuel loading. --	
	Verify measured core reactivity is within ±1% Δk/k of predicted values.	Prior to entering MODE 1 after each refueling AND -----NOTE------ Only required after 60 EFPD --------------- 31 EFPD thereafter

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.011

Question:

(Section 16.1, TS 3.1.3)

A. Please correct the following errors in the AP1000 TS 3.1.3 SRs:

- AP1000 SR 3.1.3.3 Notes should be revised to match the format of STS SR 3.1.3.2; the Note in the Frequency column should be put in the Surveillance column as Note 1, and the other two notes should be renumbered as Notes 2 and 3.
- AP1000 SR 3.1.3.2 should be considered for deletion because STS 3.1.3 no longer includes this SR; with this deletion, SR 3.1.3.3 should be renumbered as SR 3.1.3.2. Make appropriate Bases changes.
- The Notes to be renumbered as Notes 2 and 3 in renumbered SR 3.1.3.2 should refer to SR 3.1.3.2, not SR 3.1.4.3.

B. AP1000 RAI 440.015B addresses the affect of a positive moderator temperature coefficient (MTC) on TS 3.1.3 and asked: "If indeed the MTC is positive, how will it impact the Technical Specification (TS) associated with the MTC?" Does a limit on unfavorable exposure time (UET) need to be included in TSs? The first sentence of the third paragraph of the AP1000 TS 3.1.3 Bases discussion of the Applicable Safety Analyses should be changed from "least negative" to "positive" similar to the STS. Also, are any related changes needed to AP1000 TS 5.6.5.b to describe the reference document containing the approved method of controlling UET? (See discussion on similar issue in Exelon Generating Company, LLC, letter to NRC, dated March 19, 2002, requesting license amendments to modify the method of controlling UET for Byron and Braidwood Stations, ADAMS Accession No. ML020910469.) Also note that DCD paragraph 1.2.1.2.1 page 1.2-6, third bullet, states that the AP1000 "core is designed with a moderator temperature coefficient that is non-positive . . . " Reconcile this statement with the potential for positive MTC addressed in RAI 440.015B.

NOTE: AP1000 RAI 440.015B was issued on September 18, 2002 (ADAMS Accession No. ML022610042).

Westinghouse Response:

A. SR 3.1.3 and its Bases are being modified to be consistent with STS, Rev. 2 as indicated below.

NOTE: These changes are also captured in the AP1000 Technical Specification changes to update to STS Revision 2 (see RAI 630.001).

B. The AP1000 moderator temperature coefficient (MTC) is not positive during power operation, and therefore, does not impact TS 3.1.3 which is applicable only to Modes 1, 2 and 3 (also see response to RAI 440.015).

The AP1000 ATWS analysis presented in Appendix A of the AP1000 PRA demonstrates that the peak AP1000 RCS pressure is less than 3200 psig with a UET of 0. This is a result of the operation of the passive safety systems, as well as the lower MTC associated with the lower core boron concentration of the AP1000. Refer to PRA Appendix A for additional discussion of the AP1000 ATWS analysis assumptions. In addition, see RAI 440.014 for additional information regarding the compliance of the AP1000 ATWS analysis to the ATWS Rule.

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

Design Control Document (DCD) Revision:

DCD Chapter 16.1, Technical Specification 3.1.3, pg 3.1-5:

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.1.3.1 Verify MTC within upper limit.	~~Once p~~Prior to entering MODE 1 after each refueling
~~SR 3.1.3.2 Verify MTC is within 300 ppm surveillance limit specified in the COLR.~~	~~-----NOTE----- Not required to be performed until 7 effective full power days (EFPD) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm~~ ~~Once each cycle~~
SR 3.1.3.~~3~~2 -----NOTES----- 1. **Not required to be performed until 7 effective full power days (EFPD) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm.**	~~-----NOTE----- Not required to be performed until 7 EFPD after reaching the equivalent of an equili-~~

~~1.~~2. If the MTC is more negative than the 300 ppm Surveillance limit (not LCO limit) specified in the COLR, SR 3.1.~~4.3~~3.2 shall be repeated once per ~~7~~14 EFPD during the remainder of the fuel cycle. ~~2.~~3. SR 3.1.~~4.3~~3.2 need not be repeated if the MTC measured at the equivalent of equilibrium RTP-ARO boron concentration of ≤ 60 ppm is less negative than the 60 ppm Surveillance limit specified in the COLR. --	~~brium RTP-ARO boron concen- tration of 300 ppm~~ ————
Verify MTC is within lower limit.	Once each cycle

DCD Chapter 16.1, Technical Specification B 3.1.3, pg B 3.1-18:

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.3.2 ~~and SR 3.1.3.3~~

In similar fashion, the LCO demands that the MTC be less negative than the specified value for EOC full power conditions. This measurement may be performed at any THERMAL POWER, but its results must be extrapolated to the conditions of RTP and all banks withdrawn in order to make a proper comparison with the LCO value. Because the RTP MTC value will gradually become more negative with further core depletion and boron concentration reduction, a 300 ppm SR value of MTC should necessarily be less negative than the EOC LCO limit. The 300 ppm SR value is sufficiently less negative than the EOC LCO limit value to provide assurance that the LCO limit will be met at EOC when the 300 ppm Surveillance criterion is met.

SR 3.1.3.~~3~~2 is modified by **three**~~a~~ Notes that includes the following requirements:

a. The SR is not required to be performed until 7 effective full power days (EFPDs) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm.

~~a~~b. If the 300 ppm Surveillance limit is exceeded, it is possible that the EOC limit on MTC could be reached before the planned EOC. Because the MTC changes slowly with core depletion, the ~~surveillance f~~Frequency of ~~7~~14 effective full power days is sufficient to avoid exceeding the EOC limit.

~~b~~c. The Surveillance limit for RTP boron concentration of 60 ppm is conservative. If the measured MTC at 60 ppm is more positive than the 60 ppm surveillance limit, the EOC limit will not be exceeded because of the gradual manner in which MTC changes with core burnup.

From DCD Chapter 1, Section 1.2.1.2.1.2, page 1.2-6:

1.2.1.2.1 Reactor Design

- The core is designed for an 18-month fuel cycle.
- There are no reactor vessel penetrations below the top of the core.
- The core is designed for a moderator temperature coefficient that is non-positive over the entire fuel cycle ~~and~~ at any power level with the reactor coolant at the normal operating temperature.

PRA Revision:

None

3.1 REACTIVITY CONTROL SYSTEMS

3.1.3 Moderator Temperature Coefficient (MTC)

LCO 3.1.3 The MTC shall be maintained within the limits specified in the COLR.

APPLICABILITY: MODE 1, and MODE 2 with $k_{eff} \geq 1.0$ for the upper MTC limit, MODES 1, 2, and 3 for the lower MTC limit.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. MTC not within upper limit.	A.1 Establish administrative withdrawal limits for control banks to maintain MTC within limit.	24 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 2 with $k_{eff} < 1.0$.	6 hours
C. MTC not within lower limit.	C.1 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.3.1	Verify MTC within upper limit.	Prior to entering MODE 1 after each refueling
SR 3.1.3.2	-----------------NOTES------------------ 1. Not required to be performed until 7 effective full power days (EFPD) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm. 2. If the MTC is more negative than the 300 ppm Surveillance limit (not LCO limit) specified in the COLR, SR 3.1.3.2 shall be repeated once per 14 EFPD during the remainder of the fuel cycle. 3. SR 3.1.3.2 need not be repeated if the MTC measured at the equivalent of equilibrium RTP-ARO boron concentration of ≤ 60 ppm is less negative than the 60 ppm Surveillance limit specified in the COLR. --- Verify MTC is within lower limit.	Once each cycle

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to GDC 11 (Ref. 1), the reactor core and its interaction with the Reactor Coolant System (RCS) must be designed for inherently stable power operation even in the possible event of an accident. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases.

The MTC relates a change in core reactivity to a change in reactor coolant temperature (a positive MTC means that reactivity increases with increasing moderator temperature; conversely, a negative MTC means that reactivity decreases with increasing moderator temperature). The reactor is designed to operate with a non-positive MTC over the range of fuel cycle operation. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements. Both initial and reload cores are designed so that the MTC is less than zero when THERMAL POWER is at RTP. The actual value of the MTC is dependent on core characteristics such as fuel loading and reactor coolant soluble boron concentration. The core design may require additional fixed distributed poisons (burnable absorbers) to yield an MTC within the range analyzed in the plant accident analysis. The end of cycle (EOC) MTC is also limited by the requirements of the accident analysis. Fuel cycles designed to achieve high burnups that have changes to other characteristics are evaluated to ensure that the MTC does not exceed the EOC limit.

The limitations on MTC are provided to ensure that the value of this coefficient remains within the limiting conditions assumed in the Chapter 15 accident and transient analyses (Ref. 2).

(continued)

BASES

BACKGROUND (continued)

If the LCO limits are not met, the plant response during transients may not be as predicted. The core could violate criteria that prohibit a return to criticality, or the departure from nucleate boiling ratio criteria of the approved correlation may be violated, which could lead to a loss of the fuel cladding integrity.

The SRs for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains within its limits since this coefficient changes slowly due principally to the RCS boron concentration associated with fuel burnup and burnable absorbers.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the specified MTC are:

a. The MTC values must remain within the bounds of those used in the accident analysis (Ref. 2); and

b. The MTC must be such that inherently stable power operations result during normal operation and accidents, such as overheating and overcooling events.

Chapter 15 (Ref. 2) contains analyses of accidents that result in both overheating and overcooling of the reactor core. MTC is one of the controlling parameters for core reactivity in these accidents. Both the least negative value and most negative value of the MTC are important to safety, and both values must be bounded. Values used in the analyses consider worst case conditions to ensure that the accident results are bounding (Ref. 3).

The consequences of accidents that cause core heat-up must be evaluated when the MTC is least negative. Such accidents include the rod withdrawal transient from either zero (Ref. 2) or RTP, loss of main feedwater flow, and loss of forced reactor coolant flow. The consequences of accidents that cause core overcooling must be evaluated when the MTC is negative. Such accidents include sudden feedwater flow increase and sudden decrease in feedwater temperature.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

In order to ensure a bounding accident analysis, the MTC is assumed to be its most limiting value for the analysis conditions appropriate to each accident. The bounding value is determined by considering rodded and unrodded conditions, whether the reactor is at full or zero power, and whether it is BOC or EOC. The most conservative combination appropriate to the accident is then used for the analysis (Ref. 2).

MTC values are bounded in reload safety evaluations assuming steady state conditions at the limiting time in cycle life. An EOC measurement is conducted at conditions when the RCS boron concentration reaches approximately 300 ppm. The measured value may be extrapolated to project the EOC value, in order to confirm reload design predictions.

MTC satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed and controlled from the control room, MTC is considered an initial condition process variable because of its dependence on boron concentration.

LCO

LCO 3.1.3 requires the MTC to be within specified limits of the COLR to ensure that the core operates within the assumptions of the accident analysis. During the reload core safety evaluation, the MTC is analyzed to determine that its values remain within the bounds of the accident analysis during operation.

Assumptions made in safety analyses require that the MTC be more negative than a given upper limit and less negative than a given lower limit. The MTC is least negative near BOC; this upper bound must not be exceeded. This maximum upper limit occurs at all rods out (ARO), hot zero power conditions. At EOC the MTC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

During operation, therefore, the conditions of the LCO can only be ensured through measurement. The surveillance checks at BOC and EOC on MTC provide confirmation that the MTC is behaving as anticipated so that the acceptance criteria are met.

(continued)

BASES

LCO (continued)

The BOC limit and the EOC limit are established in the COLR to allow specifying limits for each particular cycle. This permits the unit to take advantage of improved fuel management and changes in unit operating schedule.

APPLICABILITY

Technical Specifications place both LCO and SR values on MTC, based on the safety analysis assumptions described above.

In MODE 1, the limits on MTC must be maintained to assure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2, with the reactor critical, the upper limit must also be maintained to ensure that startup and subcritical accidents (such as the uncontrolled CONTROL ROD assembly or group withdrawal) will not violate the assumptions of the accident analysis. The lower MTC limit must be maintained in MODES 2 and 3, in addition to MODE 1, to ensure that cooldown accidents will not violate the assumptions of the accident analysis. In MODES 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents (DBAs) using the MTC as an analysis assumption are initiated from these MODES.

ACTIONS

A.1

If the upper MTC limit is violated, administrative withdrawal limits for control banks must be established to maintain the MTC within its limits. The MTC becomes more negative with control bank insertion and decreased boron concentration. A Completion Time of 24 hours provides enough time for evaluating the MTC measurement and computing the required bank withdrawal limits.

As cycle burnup is increased, the RCS boron concentration will be reduced. The reduced boron concentration causes the MTC to become more negative. Using physics calculations, the time in cycle life at which the calculated MTC will meet the LCO requirement can be determined. At this point in core life, Condition A no longer exists. The unit is no longer in the Required Action, so the administrative withdrawal limits are no longer in effect.

(continued)

BASES

ACTIONS (continued)

B.1

If the required administrative withdrawal limits at BOC are not established within 24 hours, the unit must be placed in MODE 2 with $k_{eff} < 1.0$ to prevent operation with an MTC which is less negative than that assumed in safety analyses.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

C.1

Exceeding the EOC MTC limit means that the safety analysis assumptions for the EOC accidents that use a bounding negative MTC value may be invalid. If the EOC MTC limit is exceeded, the plant must be placed in a MODE or Condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 4 within 12 hours.

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

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

This SR requires measurement of the MTC at BOC prior to entering MODE 1 in order to demonstrate compliance with the most limiting MTC LCO. Meeting the limit prior to entering MODE 1 assures that the limit will also be met at higher power levels.

The BOC MTC value for ARO will be inferred from isothermal temperature coefficient measurements obtained during the physics tests after refueling. The ARO value can be directly compared to the MTC limit of the LCO. If required, measurement results and predicted design values can be used to establish administrative withdrawal limits for control banks.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.3.2

In similar fashion, the LCO demands that the MTC be less negative than the specified value for EOC full power conditions. This measurement may be performed at any THERMAL POWER, but its results must be extrapolated to the conditions of RTP and all banks withdrawn in order to make a proper comparison with the LCO value. Because the RTP MTC value will gradually become more negative with further core depletion and boron concentration reduction, a 300 ppm SR value of MTC should necessarily be less negative than the EOC LCO limit. The 300 ppm SR value is sufficiently less negative than the EOC LCO limit value to provide assurance that the LCO limit will be met at EOC when the 300 ppm Surveillance criterion is met.

SR 3.1.3.2 is modified by three Notes that include the following requirements:

a. The SR is not required to be performed until 7 effective full power days (EFPDs) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm.

b. If the 300 ppm Surveillance limit is exceeded, it is possible that the EOC limit on MTC could be reached before the planned EOC. Because the MTC changes slowly with core depletion, the Frequency of 14 effective full power days is sufficient to avoid exceeding the EOC limit.

c. The Surveillance limit for RTP boron concentration of 60 ppm is conservative. If the measured MTC at 60 ppm is more positive than the 60 ppm surveillance limit, the EOC limit will not be exceeded because of the gradual manner in which MTC changes with core burnup.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 11.
2. Chapter 15, "Accident Analysis."
3. WCAP 9273-NP-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

RAI Number: 630.012

Question:

(Section 16.1, TSs 3.1.4, 3.1.5, 3.1.6 and 3.1.8) Consider revising action requirements of TSs 3.1.4, 3.1.5, 3.1.6 and 3.1.8 to refer to the shutdown margin (SDM) limit specified in the core operating limits report (COLR), instead of a specific value (this would be consistent with the STS which assume the COLR exists).

Westinghouse Response:

TSs 3.1.4, 3.1.5, 3.1.6, 3.1.8 will be modified to be consistent with STS, Rev. 2 as indicated below to refer to the SDM limit specified in the COLR instead of a specific value.

NOTE: These changes are also captured in the AP1000 Technical Specification changes to update to STS Revision 2 (see RAI 630.001).

Design Control Document (DCD) Revision:

DCD Chapter 16.1, Technical Specification 3.1.4, pg 3.1-6:

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more rod(s) ~~untrippable~~**inoperable.**	A.1.1 Verify SDM ~~is ≥ 1.6 Δk/k~~ **to be within the limits specified in the COLR.** OR A.1.2 Initiate boration to restore SDM within limit. AND A.2 Be in MODE 3.	1 hour 1 hour 6 hours

(continued)

DCD Chapter 16.1, Technical Specification 3.1.4, pg 3.1-7:

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One rod not within alignment limits.	B.1 ~~------NOTE------ Maintain bank sequence and insertion limits of LCO 3.1.5 and LCO 3.1.6, with changes to rod position or THERMAL POWER level, during subsequent operation.~~	
	Restore rod, to within alignment limits.	8 hours with the On-Line Power Distribution Monitoring System (OPDMS) OPERABLE OR 1 hour with the OPDMS inoperable
	OR	
	B.2.1.1 Verify SDM ~~≥ 1.6 Δk/k~~ **to be within the limits specified in the COLR.** OR	1 hour

	B.2.1.2	Initiate boration to restore SDM within limit.	1 hour
	<u>AND</u> B.2.2	Reduce THERMAL POWER to $\leq$ 75% RTP.	2 hours
	<u>AND</u>		(continued)

DCD Chapter 16.1, Technical Specification 3.1.4, pg 3.1-8:

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2.3 Verify SDM ~~≥ 1.6 Δk/k~~is **within the limits specified in the COLR.** <u>AND</u> --------NOTE-------- Only required to be performed when OPDMS is inoperable. ------------------	Once per 12 hours
	B.2.4 Perform SR 3.2.1.1 ($F_Q(Z)$ verification)~~.~~ **and SR 3.2.1.2 ($F_Q^W(Z)$ verification).** <u>AND</u> --------NOTE-------- Only required to be performed when OPDMS is inoperable. ------------------	72 hours
	B.2.5 Perform SR 3.2.2.1 ($F^N_{\Delta H}$ verification). <u>AND</u>	72 hours

		B.2.6	Re-evaluate safety analyses and confirm results remain valid for duration of operation under these conditions.	5 days
C.	Required Action and associated Completion Time for Condition B not met.	C.1	Be in MODE 3.	6 hours

(continued)

DCD Chapter 16.1, Technical Specification 3.1.4, pg. 3.1-9:

ACTIONS (continued)

CONDITION		REQUIRED ACTION		COMPLETION TIME
D.	More than one rod not within alignment limit.	D.1.1	Verify SDM ~~≥ 1.6 Δk/k~~us **within the limits specified in the COLR.**	1 hour
		<u>OR</u>		
		D.1.2	Initiate boration to restore required SDM to within limit.	1 hour
		<u>AND</u>		
		D.2	Be in MODE 3.	6 hours

DCD Chapter 16.1, Technical Specification 3.1.5, pg 3.1-11:

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more shutdown banks not within limits.	A.1.1 Verify SDM is ~~≥ 1.6% Δk/k~~ **within the limits specified in the COLR.**	1 hour
	<u>OR</u>	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	<u>AND</u>	
	A.2 Restore shutdown banks to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

DCD Chapter 16.1, Technical Specification 3.1.6, pg 3.1-13:

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Control Bank insertion limits not met.	A.1.1 Verify SDM is ~~≥ 1.6% Δk/k~~**within the limits specified in the COLR.**	1 hour
	<u>OR</u>	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	<u>AND</u>	
	A.2 Restore control bank(s) to within limits.	2 hours

(continued)

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

DCD Chapter 16.1, Technical Specification 3.1.6, pg 3.1-14:

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Control bank sequence or overlap limits not met.	B.1.1 Verify SDM is ~~≥ 1.6% Δk/k~~**within the limits specified in the COLR.**	1 hour
	<u>OR</u>	
	B.1.2 Initiate boration to restore SDM to within limit.	1 hour
	<u>AND</u>	
	B.2 Restore control bank sequence and overlap to within limits.	2 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE ~~3~~**2 with K_{eff} < 1.0..**	6 hours

DCD Chapter 16.1, Technical Specification 3.1.8, pg 3.1-18:

3.1 REACTIVITY CONTROL SYSTEMS

3.1.8 PHYSICS TESTS Exceptions — MODE 2

LCO 3.1.8 During the performance of PHYSICS TESTS, the requirements of

LCO 3.1.3 "Moderator Temperature Coefficient,"
LCO 3.1.4 "Rod Group Alignment Limits,"
LCO 3.1.5 "Shutdown Bank Insertion Limit,"
LCO 3.1.6 "Control Bank Insertion Limits," and
LCO 3.4.2 "RCS Minimum Temperature for Criticality"

may be suspended**, and the number of required channels for LCO 3.3.1, "RTS Instrumentation," Functions 2, 3, 6, and 18.c, may be reduced to 3** provided:

a. RCS lowest loop average temperature is ≥ [535°F],~~; and~~

b. SDM is ~~≥ 1.6% Δk/k~~**within limits specified in the COLR**~~.~~**, and**

c. **THERMAL POWER is < 5% RTP.**

APPLICABILITY: ~~MODE 2 during PHYSICS TESTS.~~**During PHYSICS TESTS initiated in MODE 2.**

DCD Chapter 16.1, Technical Specification 3.1.8, pg 3.1-19:

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.8.1	Perform a CHANNEL OPERATIONAL TEST on power range and intermediate range channels per SR 3.3.1.5.	~~Within 12 hours~~ ~~p~~Prior to initiation of PHYSICS TESTS
SR 3.1.8.2	Verify the ~~thermal power and the~~ RCS lowest loop average temperature ~~are within limits~~is ≥ [535] °F.	30 minutes
SR 3.1.8.3	**Verify THERMAL POWER is < 5% RTP.**	**30 minutes**
SR 3.1.8.4~~3~~	Verify SDM is ~~≥ 1.6% Δk/k~~**within the limits specified in the COLR.**	24 hours

PRA Revision:

None

3.1 REACTIVITY CONTROL SYSTEMS

3.1.4 Rod Group Alignment Limits

LCO 3.1.4 All shutdown and control rods shall be OPERABLE. Individual indicated rod positions shall be within 12 steps of their group step counter demand position.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more rod(s) inoperable.	A.1.1 Verify SDM to be within the limits specified in the COLR.	1 hour
	<u>OR</u>	
	A.1.2 Initiate boration to restore SDM within limit.	1 hour
	<u>AND</u>	
	A.2 Be in MODE 3.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One rod not within alignment limits.	B.1 Restore rod, to within alignment limits.	8 hours with the On-Line Power Distribution Monitoring System (OPDMS) OPERABLE OR 1 hour with the OPDMS inoperable
	OR	
	B.2.1.1 Verify SDM to be within the limits specified in the COLR.	1 hour
	OR	
	B.2.1.2 Initiate boration to restore SDM within limit.	1 hour
	AND	
	B.2.2 Reduce THERMAL POWER to ≤ 75% RTP.	2 hours
	AND	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2.3 Verify SDM is within the limits specified in the COLR. AND ---------NOTE--------- Only required to be performed when OPDMS is inoperable. ----------------------	Once per 12 hours
	B.2.4 Perform SR 3.2.1.1 ($F_Q(Z)$ verification) and SR 3.2.1.2 ($F_Q^W(Z)$ verification). AND ---------NOTE--------- Only required to be performed when OPDMS is inoperable. ----------------------	72 hours
	B.2.5 Perform SR 3.2.2.1 ($F^N_{\Delta H}$ verification). AND	72 hours
	B.2.6 Re-evaluate safety analyses and confirm results remain valid for duration of operation under these conditions.	5 days

C. Required Action and associated Completion Time for Condition B not met.	C.1 Be in MODE 3.	6 hours

(continued)

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. More than one rod not within alignment limit.	D.1.1 Verify SDM is within the limits specified in the COLR.	1 hour
	<u>OR</u>	
	D.1.2 Initiate boration to restore required SDM to within limit.	1 hour
	<u>AND</u>	
	D.2 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify individual rod positions within alignment limit.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.4.2	Verify rod freedom of movement (trippability) by moving each rod not fully inserted in the core ≥ 10 steps in either direction.	92 days
SR 3.1.4.3	Verify rod drop time of each rod, from the fully withdrawn position, is ≤ [2.47] seconds from the beginning of decay of stationary gripper coil voltage to dashpot entry, with: a. $T_{avg} \geq 500°F$, and b. All reactor coolant pumps operating.	Prior to reactor criticality after each removal of the reactor head

3.1 REACTIVITY CONTROL SYSTEMS

3.1.5 Shutdown Bank Insertion Limits

LCO 3.1.5 Each Shutdown Bank shall be within insertion limits specified in the COLR.

APPLICABILITY: MODES 1 and 2.

-------------------------NOTE-------------------------
This LCO is not applicable while performing SR 3.1.4.2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more shutdown banks not within limits.	A.1.1 Verify SDM is within the limits specified in the COLR. OR A.1.2 Initiate boration to restore SDM to within limit. AND A.2 Restore shutdown banks to within limits.	1 hour 1 hour 2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.5.1	Verify each shutdown bank is within the insertion limits specified in the COLR.	12 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.6 Control Bank Insertion Limits

LCO 3.1.6 Control banks shall be within the insertion, sequence, and overlap limits specified in the COLR.

APPLICABILITY: MODE 1,
MODE 2 with $k_{eff} \geq 1.0$.

-------------------------NOTE-------------------------
This LCO is not applicable while performing SR 3.1.4.2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Control Bank insertion limits not met.	A.1.1 Verify SDM is within the limits specified in the COLR.	1 hour
	OR	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	AND	
	A.2 Restore control bank(s) to within limits.	2 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Control bank sequence or overlap limits not met.	B.1.1 Verify SDM is within the limits specified in the COLR.	1 hour
	<u>OR</u>	
	B.1.2 Initiate boration to restore SDM to within limit.	1 hour
	<u>AND</u>	
	B.2 Restore control bank sequence and overlap to within limits.	2 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 2 with $k_{eff} < 1.0$.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.6.1	Verify the estimated critical control bank position is within limits specified in the COLR.	Within 4 hours prior to achieving criticality
SR 3.1.6.2	Verify each control bank insertion is within the limits specified in the COLR.	12 hours
SR 3.1.6.3	Verify sequence and overlap limits, specified in the COLR, are met for control banks not fully withdrawn from the core.	12 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.8 PHYSICS TESTS Exceptions – MODE 2

LCO 3.1.8 During the performance of PHYSICS TESTS, the requirements of

LCO 3.1.3 "Moderator Temperature Coefficient,"
LCO 3.1.4 "Rod Group Alignment Limits,"
LCO 3.1.5 "Shutdown Bank Insertion Limit,"
LCO 3.1.6 "Control Bank Insertion Limits," and
LCO 3.4.2 "RCS Minimum Temperature for Criticality"

may be suspended, and the number of required channels for LCO 3.3.1, "RTS Instrumentation," Functions 2, 3, 6, and 18.c, may be reduced to 3 provided:

a. RCS lowest loop average temperature is ≥ [535°F],

b. SDM is within the limits specified in the COLR, and

c. THERMAL POWER is < 5% RTP.

APPLICABILITY: During PHYSICS TESTS initiated in MODE 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limit. AND A.2 Suspend PHYSICS TEST exceptions.	15 minutes 1 hour
B. THERMAL POWER not within limit	B.1 Open reactor trip breakers.	Immediately

C. RCS lowest loop average temperature not within limit.	C.1 Restore RCS lowest loop average temperature to within limit.	15 minutes

(continued)

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and Associated Completion Time of Condition C not met.	D.1 Be in MODE 3.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.8.1	Perform a CHANNEL OPERATIONAL TEST on power range and intermediate range channels per SR 3.3.1.5.	Prior to initiation of PHYSICS TESTS
SR 3.1.8.2	Verify the RCS lowest loop average temperature is ≥ [535] °F.	30 minutes
SR 3.1.8.3	Verify THERMAL POWER is < 5% RTP.	30 minutes
SR 3.1.8.4	Verify SDM is within the limits specified in the COLR.	24 hours

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.013

Question:

(Section 16.1, TS Section 3.2) Acceptance of TS Section 3.2 requires resolution of RAI 440.102. Please resolve this issue and revise the DCD/TSs accordingly.

NOTE: AP1000 RAI 440.102 was issued on September 18, 2002 (ADAMS Accession No. ML022610042).

Westinghouse Response:

See response to RAI 440.102.

Design Control Document (DCD) Revision:

See RAI 440.102 for the DCD and Technical Specification changes.

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.014

Question:

(Section 16.1, TS Section 3.3) Acceptance of TS Section 3.3 requires resolution of RAIs 420.034, 420.041, 420.042, 440.103, 440.111, 440.117, and 440.120. Please resolve these issues and revise the DCD/TSs accordingly.

NOTE: AP1000 RAIs 420.034, 420.041, and 420.042 were issued on August 27, 2002 (ADAMS Accession No. ML022390103). AP1000 RAIs 440.103, 440.111, 440.117, and 440.120 were issued on September 18, 2002 (ADAMS Accession No. ML022610042).

Westinghouse Response:

There were no changes to the AP1000 Technical Specifications resulting from responses to RAIs 420.034, 420.041, 420.042, 440.111, and 440.120. The changes to the AP1000 Technical Specifications and DCD Section15.2.7 resulting from RAIs 440.103 and 440.117 are included in the response to these RAIs.

Design Control Document (DCD) Revision:

See responses to RAI 440.103 and 440.117.

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.015

Question:

(Section 16.1, TS 3.3.1) The word "inoperable" is unnecessary in TS 3.3.1 Actions Note and should be removed. Please revise the DCD accordingly.

Westinghouse Response:

This change is being made as part of the change to Revision 2 of the Standard Technical Specifications. See response to RAI 630.001.

Design Control Document (DCD) Revision:

See response to RAI 630.001.

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.016

Question:

(Section 16.1, TSs 3.3.1 and 3.3.2) Similar to RAIs 420.041 and 420.042 (quoted below), explain why TS 3.3.1 Required Actions D.1.2, D.1.3, E.1.2, F.1.2, K.1.2, and L.1.2, as proposed, were not needed for the AP600 reactor protection system (RPS), but are needed for the AP1000 RPS design? Also explain the same for TS 3.3.2 Required Actions B.1, B.2, I.1, I.2, J.2.1, and J.2.2.

A. 420.041 (DCD 16.1, TS LCO 3.3.1) TS LCO 3.3.1 Conditions N and O has added new Required Actions, N.2.2 and O.2.2, respectively, which states that "With two interlock channels inoperable, place the Functions associated with one inoperable interlock channel in bypass and with one inoperable interlock channel in trip." Explain why this Action is required for the AP1000 design, but was not required for the AP600 design. Are all the interlock logics using 2-out-of-4 coincident logic? Why is the wording in Required Actions N.2.1 and O.2.1 different?

B. 420.042 (DCD 16.1, TS LCO 3.3.2) TS LCO 3.3.2 Condition J has added a new Required Action J.2.2 which states that "With two interlock channels inoperable, place the Functions associated with one inoperable interlock channel in bypass and with one inoperable interlock channel in trip." Explain why this Action is required for the AP1000 design and was not required for the AP600 design. Are all the interlock logics using 2-out-of-4 coincident logic?

Please resolve these issues and revise the DCD/TSs accordingly.

NOTE: AP1000 RAIs 420.041 and 420.042 were issued on August 27, 2002 (ADAMS Accession No. ML022390103).

Westinghouse Response:

The AP600 2-out-of-4-bypass logic allows the operator to place two channels in bypass. The protection system will then automatically treat the remaining 2 channels as 1-out-of-2. The Common Q platform does not support this automatic bypass logic feature. Therefore the AP1000 2-out-of-4-bypass logic will not allow two redundant channels to be placed in bypass simultaneously. If two channels are inoperable, the operator is expected to place one inoperable channel in bypass and the other inoperable channel in trip. The protection system will then treat the remaining two channels as 1-out-of-2, accomplishing the same logic as the AP600 2-out-of-4-bypass logic. The Technical Specification changes listed below reflect this difference in operator response.

- In TS 3.3.1, AP1000 Required Actions D.1.2 and D.1.3 replace AP600 Required Action D.1.2.
- In TS 3.3.1, AP1000 Required Actions E.1.1 and E.1.2 replace AP600 Required Action E.1.
- In TS 3.3.1, AP1000 Required Actions F.1.1 and F.1.2 replace AP600 Required Action F.1.
- In TS 3.3.1, AP1000 Required Actions K.1.1 and K.1.2 replace AP600 Required Action K.1.
- In TS 3.3.1, AP1000 Required Actions L.1.1 and L.1.2 replace AP600 Required Action L.1.
- In TS 3.3.2, AP1000 Required Actions B.1 and B.2 replace AP600 Required Action B.1.
- In TS 3.3.2, AP1000 Required Actions I.1 and I.2 replace AP600 Required Action I.1.
- In TS 3.3.2, AP1000 Required Actions J.2.1 and J.2.2 replace AP600 Required Action J.2.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.017

Question:

(Section 16.1, TS 3.3.2) TS 3.3.2 Required Action B.2 should address two inoperable divisions as well as two inoperable channels because Condition B applies to engineered safety feature actuation system (ESFAS) Functions 15.c and 20.b. Please revise the DCD accordingly.

Westinghouse Response:

Westinghouse agrees to revise the TS 3.3.1 Required Actions B.1 and B.2 and bases as shown below.

Design Control Document (DCD) Revision:

LCO 3.3.2 The ESFAS instrumentation for each function in Table 3.3.2-1 shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or divisions inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or division(s).	Immediately
B. One or two channels or divisions inoperable.	B.1 Place one inoperable channel ~~and~~ **or** division in bypass or trip.	6 hours
	AND	
	B.2 **With two inoperable channels or divisions, place one inoperable channel or division in bypass and one inoperable channel or division in trip.**	6 hours

B 3.3.2 ENGINEERED SAFETY FEATURE ACTUATION SYSTEM (ESFAS) INSTRUMENTATION

BASES

ACTIONS

B.1 and B.2

With one or two channels **or divisions** inoperable, one affected channel **or division** must be placed in a bypass or trip condition within 6 hours. If one channel **or division** is bypassed, the logic becomes two-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels **or divisions** will not prevent the protective function.) If one channel **or division** is tripped, the logic becomes one-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels **or divisions** will not prevent the protective function.) If one channel **or division** is bypassed and one channel **or division** is tripped, the logic becomes one-out-of-two, while still meeting the single failure criterion. The 6 hours allowed to place the inoperable channel(s) **or division(s)** in the bypassed or tripped condition is justified in Reference 7.

PRA Revision:

None

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

LCO 3.3.2 The ESFAS instrumentation for each function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1.

ACTIONS

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

1. Separate condition entry is allowed for each Function.
2. The Conditions for each Function are given in Table 3.3.2-1. If the Required Actions and associated Completion Times of the first Condition are not met, refer to the second Condition.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or divisions inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or division(s).	Immediately
B. One or two channels or divisions inoperable.	B.1 Place one inoperable channel or division in bypass or trip.	6 hours
	<u>AND</u>	
	B.2 With two inoperable channels or divisions, place one inoperable channel or division in bypass and one inoperable channel or division in trip.	6 hours

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C. One channel inoperable.	C.1 Place inoperable channel in bypass.	6 hours

(continued)

RAI Number 630.017-4

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BASES

ACTIONS (continued)

A second Note has been added to provide clarification that, more than one Condition is listed for each of the Functions in Table 3.3.2-1. If the Required Action and associated Completion Time of the first Condition listed in Table 3.3.2-1 is not met, the second Condition shall be entered.

In the event a channel's Nominal Trip Setpoint is not met, or the transmitter, or the Protection and Safety Monitoring System Division, associated with a specific Function is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the particular protection Function(s) affected. When the Required Channels are specified only on a per steam line, per loop, per SG, basis, then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

When the number of inoperable channels in a trip function exceed those specified in one or other related Conditions associated with a trip function, then the plant is outside the safety analysis. Therefore, LCO 3.0.3 in MODES 1 through 4 and LCO 3.0.8 for MODE 5 and 6 should be immediately entered if applicable in the current MODE of operation.

A.1

Condition A is applicable to all ESFAS protection Functions. Condition A addresses the situation where one or more channels/divisions for one or more functions are inoperable at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection Functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1 and B.2

With one or two channels or divisions inoperable, one affected channel or division must be placed in a bypass or trip condition within 6 hours. If one channel or division is bypassed, the logic becomes two-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels or divisions will not

(continued)

ACTIONS

B.1 and B.2 (continued)

prevent the protective function.) If one channel or division is tripped, the logic becomes one-out-of-three, while still meeting the single failure criterion. (A failure in one of the three remaining channels or divisions will not prevent the protective function.) If one channel or division is bypassed and one channel or division is tripped, the logic becomes one-out-of-two, while still meeting the single failure criterion. The 6 hours allowed to place the inoperable channel(s) or division(s) in the bypassed or tripped condition is justified in Reference 7.

C.1

With one channel inoperable, the affected channel must be placed in a bypass condition within 6 hours. The 6 hours allowed to place the inoperable channel in the bypass condition is justified in Reference 6. If one CVS isolation channel is bypassed, the logic becomes one-out-of-one. A single failure in the remaining channel could cause a spurious CVS isolation. Spurious CVS isolation, while undesirable, would not cause an upset plant condition.

D.1

With one required division inoperable, the affected division must be restored to OPERABLE status within 6 hours.

Condition D applies to one inoperable required division of P-4 Interlock (Function 18.a). With one required division inoperable, the 2 remaining OPERABLE divisions are capable of providing the required interlock function, but without a single failure. The P-4 Interlock is enabled when RTBs in two divisions are detected as open. The status of the other inoperable, non-required P-4 division is not significant, since P-4 divisions can not be tripped or bypassed. In order to provide single failure tolerance, 3 required divisions must be OPERABLE.

Condition D also applies to one inoperable division of ESF coincidence logic or ESF actuation (Functions 25 and 26). The ESF coincidence logic and ESF actuation divisions are inoperable when their associated battery-backed subsystem is inoperable. With one inoperable division, the 3 remaining OPERABLE divisions are capable of mitigating all DBAs, but without a single failure.

(continued)

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.018

Question:

(Section 16.1, TSs 3.3.1 and 3.4.1) STS Table 3.3.1-1, Notes 1 and 2, refer to the COLR for the values of constants used in the equations for Overtemperature ΔT and Overpower ΔT nominal trip setpoints. Consider doing the same for the AP1000 TSs provided the bracketed values are included elsewhere in the DCD Tier 2 information.

Westinghouse Response:

This change is being made as part of the change to Revision 2 of the Standard Technical Specifications. See response to RAI 630.001.

Design Control Document (DCD) Revision:

See response to RAI 630.001.

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.019

Question:

(Section 16.1, TS 3.3.3) The STS Table 3.3.3-1 and the AP600 TS Table 3.3.3-1 include the Power Range and Source Range Neutron Flux post-accident monitoring (PAM) functions; the AP600 also includes the Intermediate Range Neutron Flux PAM function. Why does the proposed AP1000 TS Table 3.3.3-1 Function 1 only include the Intermediate Range Neutron Flux PAM function? (Note that the markup of the AP600 TS Bases for PAM Function 1 seems to indicate that the AP600 TSs only required the Intermediate Range Neutron Flux.) Does the AP1000 intermediate range instrument cover both the source and power range? The STS Bases gives adequate neutron flux coverage as a basis for its requirement. Why is such a basis missing from the AP600 and the AP1000 Bases?

Westinghouse Response:

Regulatory Guide 1.97 requires that neutron flux be monitored for post-accident situations in the range 10^{-6} to 100% of full power. As shown in DCD Table 7.5-1, the AP1000 Intermediate Range Neutron Flux Channels cover the range of 10^{-6} to 200% of full power. The Intermediate Range Neutron Flux Channels are sufficient to cover the required range of neutron flux. Therefore, the Source Range and Power Range monitors are not post-accident monitoring instrumentation and are not listed in DCD Table 7.5-1 and are not covered by Technical Specification Table 3.3.3-1.

The Technical Specification Bases will be revised as shown below to clarify that Intermediate Range Neutron Flux is sufficient to cover the required range.

Design Control Document (DCD) Revision:

B 3.3.3 Post Accident Monitoring (PAM) Instrumentation

BASES

LCO

1. Intermediate Range Neutron Flux

   Neutron Flux indication is provided to verify reactor shutdown. **The neutron flux intermediate range is sufficient to cover the full range of flux that may occur post accident.**

   Neutron flux is used for accident diagnosis, verification of subcriticality, and diagnosis of positive reactivity insertion.

PRA Revision:

None

BASES

APPLICABLE SAFETY ANALYSES (continued)

- Determine the likelihood of a gross breach of the barriers to radioactivity release;
- Determine if a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public and to estimate the magnitude of any impending threat.

PAM Instrumentation that is required in accordance with Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for those monitors which provide information required by the control room operators to assess the process of accomplishing or maintaining critical safety functions. This LCO addresses those Regulatory Guide 1.97 instruments which are listed in Table 3.3.3-1.

The OPERABILITY of the PAM Instrumentation ensures there is sufficient information available on selected plant parameters to monitor and assess plant status following an accident. This capability is consistent with the recommendations of Reference 1.

Category 1 non-type A variables are required to meet Regulatory Guide 1.97 Category 1 (Ref. 1) design and qualification requirements for seismic and environmental qualification, single-failure criterion, utilization of emergency standby power, immediately accessible display, continuous readout, and recording of display.

Listed below are discussions of the specified instrument functions listed in Table 3.3.3-1. Each of these is a Category 1 variable.

1. Intermediate Range Neutron Flux

   Neutron Flux indication is provided to verify reactor shutdown. The neutron flux intermediate range is sufficient to cover the full range of flux that may occur post accident.

   Neutron flux is used for accident diagnosis, verification of subcriticality, and diagnosis of positive reactivity insertion.

(continued)

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.020

Question:

(Section 16.1, TS 3.3.4 Required Action B.2) The Applicability of the remote shutdown workstation (RSW) differs from that of STS 3.3.4 and AP600 TS 3.3.4, which are the same except for the time to get to 350°F by Required Action B.2. Why is the AP1000 TS 3.3.4 Applicability changed to exclude Mode 4, i.e., shutdown with RCS temperature below 420°F? In addition, why are 13 hours permitted to place the plant below this temperature? Most other similar AP1000 TS Required Actions regarding placing the plant in Mode 4 allow only 12 hours, (this is less restrictive than the STS, which requires reaching an even lower RCS temperature). Please explain.

Westinghouse Response:

The applicability will be revised to match AP600.

The completion time for TS 3.3.4 Required Action B.2 will be changed from 13 hours to 12 hours as part of the change to Revision 2 of the Standard Technical Specifications. See response to RAI 630.001.

Design Control Document (DCD) Revision:

3.3 INSTRUMENTATION

3.3.4 Remote Shutdown Workstation

LCO 3.3.4 The Remote Shutdown Workstation (RSW) shall be OPERABLE.

APPLICABILITY: MODES 1, 2, ~~and~~ 3, and
MODE 4 with RCS average temperature (T_{avg})

ACTIONS

-----------------------------------NOTE-----------------------------------
LCO 3.0.4 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RSW inoperable.	A.1 Restore to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 4 with $T_{avg} < 350°F$.	~~13~~ 12 hours

B 3.3.4 Remote Shutdown Workstation (RSW)

BASES

BACKGROUND

The RSW provides the ~~main~~ control room operator with sufficient displays and controls to place and maintain the unit in a safe shutdown condition from a location other than the ~~main~~ control room. This capability is necessary to protect against the possibility that the ~~main~~ control room becomes inaccessible. Passive residual heat removal (PRHR), the core makeup tanks (CMTs), and the in-containment refueling water storage tank (IRWST) can be used to remove core decay heat. The use of passive safety systems allows extended operation in MODE 4.

If the ~~main~~ control room becomes inaccessible, the operators can establish control at the RSW and place and maintain the unit in MODE 4 with $T_{avg} < 350°F$. The unit can be maintained safely in MODE 4 with $T_{avg} < 350°F$ for an extended period of time.

The OPERABILITY of the remote shutdown control and display functions ensures there is sufficient information available on selected ~~plant~~ unit parameters to place and maintain the ~~plant~~ unit in MODE 4 with $T_{avg} < 350°F$ should the control room become inaccessible.

APPLICABLE SAFETY ANALYSES

The RSW is required to provide equipment at appropriate locations outside the ~~main~~ control room with a capability to promptly shut down and maintain the ~~plant~~ unit in a safe condition in MODE 4 with $T_{avg} < 350°F$.

The criteria governing the design and the specific system requirements of the ~~Remote Shutdown System~~RSW are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1).

Since the passive safety systems alone can establish and maintain safe shutdown conditions for the ~~plant~~unit, nonsafety systems are not required for safe shutdown of the ~~plant~~unit. Therefore, no credit is taken in the safety analysis for nonsafety systems.

The RSW ~~is considered a contributor to the reduction of unit risk to accidents and as such it has been retained in the~~

~~Technical Specifications, as indicated in the NRC Policy Statement~~satisifes Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The RSW LCO provides the ~~requirements for~~ OPERABILITY requirements of the displays and controls necessary to place and maintain the ~~plant~~ unit in MODE 4 from a location other than the ~~main~~ control room.

The RSW is OPERABLE if the display instrument and control functions needed to support the RSW are OPERABLE.

The RSW covered by this LCO ~~do~~ does not need to be energized to be considered OPERABLE. This LCO is intended to ensure the RSW will be OPERABLE if ~~plant~~ unit conditions require that the RSW be placed in operation.

APPLICABILITY

The RSW LCO is applicable in MODES 1, 2, and 3 and in MODE 4 with T_{avg} °F. This is required so that the facility can be placed and maintained in MODE 4 for an extended period of time from a location other than the ~~main~~ control room.

This LCO is not applicable in MODE 4 with T_{avg} < 350°F or in MODE 5 or 6. In ~~this~~ these MODES, the unit is already subcritical and in a condition of reduced Reactor Coolant System (RCS) energy. Under these conditions, considerable time is available to restore necessary instrument control functions if ~~main~~ control room instruments or controls become unavailable.

ACTIONS

The Note excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into an applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require a ~~plant~~ unit shutdown. This exception is acceptable due to the low probability of an event requiring the RSW and because the equipment can generally be repaired during operation without significant risk of a spurious trip.

A.1

Condition A addresses the situation where the RSW is inoperable. The Required Action is to restore the RSW to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the ~~main~~ control room.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 with T_{avg} < 350°F within ~~13~~ 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

SR 3.3.4.1 verifies that each required RSW transfer switch performs the required functions. This ensures that if the ~~main~~ control room becomes inaccessible, the unit can be placed and maintained in MODE 4 with T_{avg} < 350°F from the RSW. The 24 month Frequency was developed considering it is prudent that these types of surveillances be performed during a unit outage. However, this surveillance is not required to be performed only during a unit outage. This is due to the ~~plant~~ unit conditions needed to perform the surveillance and the potential for unplanned transients if the surveillance is performed with the reactor at power. Operating experience demonstrates that RSW transfer switches usually pass the surveillance test when performed on the 24 month Frequency.

SR 3.3.4.2

This Surveillance verifies that the RSW communicates controls and indications with Divisions A, B, C, and D of the PMS. Communication is accomplished by use of separate multiplexers for each division. The operator can select the controls and indications available through each PMS division.

The Frequency is based on the known reliability of the Functions and the redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.4 3

SR 3.3.4.3 verifies the OPERABILITY of the RSW hardware and software by performing diagnostics to show that operator displays are capable of being called up and displayed to an operator at the RSW. The RSW has several video display units which can be used by the operator. The video display units are identical to that provided in the ~~main~~ control room and the operator can display information on the video display units in a manner which is identical to the way the information is displayed in the ~~main~~ control room. The operator normally selects an appropriate set of displays based on the particular operational goals being controlled by the operator at the time. Each display consists of static graphical and legend information which is contained within the display processor associated with each video display unit and dynamic data which is updated by the data display system.

The Frequency of 24 months is based on the use of the data display capability in the ~~main~~ control room as part of the normal ~~plant~~ unit operation and the availability of multiple video display units at the RSW. The Frequency of 24 months is based upon operating experience and consistency with ~~main~~ control room hardware and software.

SR 3 3.4.4

SR 3.3.4.4 is the performance of a TRIP ACTUATING DEVICE OPERATIONAL TEST (TADOT) every 24 months. This test should verify the OPERABILITY of the reactor trip breakers (RTBs) open and closed indication on the RSW by actuating the RTBs. The Frequency of 24 months was chosen because the RTBs may not be exercised while the facility is at power and is based on operating experience and consistency with the refueling outage.

PRA Revision:

None

3.3 INSTRUMENTATION

3.3.4 Remote Shutdown Workstation

LCO 3.3.4 The Remote Shutdown Workstation (RSW) shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and
MODE 4 with RCS average temperature (T_{avg}).

ACTIONS

-----------------------------------NOTE-----------------------------------
LCO 3.0.4 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RSW inoperable.	A.1 Restore to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4 with T_{avg} < 350°F.	6 hours 12 hours

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown Workstation (RSW)

BASES

BACKGROUND

The RSW provides the control room operator with sufficient displays and controls to place and maintain the unit in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. Passive residual heat removal (PRHR), the core makeup tanks (CMTs), and the in-containment refueling water storage tank (IRWST) can be used to remove core decay heat. The use of passive safety systems allows extended operation in MODE 4.

If the control room becomes inaccessible, the operators can establish control at the RSW and place and maintain the unit in MODE 4 with T_{avg} < 350°F. The unit can be maintained safely in MODE 4 with T_{avg} < 350°F for an extended period of time.

The OPERABILITY of the remote shutdown control and display functions ensures there is sufficient information available on selected unit parameters to place and maintain the unit in MODE 4 with T_{avg} < 350°F should the control room become inaccessible.

APPLICABLE SAFETY ANALYSES

The RSW is required to provide equipment at appropriate locations outside the control room with a capability to promptly shut down and maintain the unit in a safe condition in MODE 4 with T_{avg} < 350°F.

The criteria governing the design and the specific system requirements of the RSW are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1).

Since the passive safety systems alone can establish and maintain safe shutdown conditions for the unit, nonsafety systems are not required for safe shutdown of the unit. Therefore, no credit is taken in the safety analysis for nonsafety systems.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The RSW satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	The RSW LCO provides the OPERABILITY requirements of the displays and controls necessary to place and maintain the unit in MODE 4 from a location other than the control room. The RSW is OPERABLE if the display instrument and control functions needed to support the RSW are OPERABLE. The RSW covered by this LCO does not need to be energized to be considered OPERABLE. This LCO is intended to ensure the RSW will be OPERABLE if unit conditions require that the RSW be placed in operation.
APPLICABILITY	The RSW LCO is applicable in MODES 1, 2, and 3 and in MODE 4 with T_{avg} < 350°F. This is required so that the facility can be placed and maintained in MODE 4 for an extended period of time from a location other than the control room. This LCO is not applicable in MODE 4 with T_{avg} < 350°F or in MODE 5 or 6. In these MODES, the unit is already subcritical and in a condition of reduced Reactor Coolant System (RCS) energy. Under these conditions, considerable time is available to restore necessary instrument control functions if control room instruments or controls become unavailable.
ACTIONS	The Note excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into an applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require a unit shutdown. This exception is acceptable due to the low probability of an event requiring the RSW and because the equipment can generally be repaired during operation without significant risk of a spurious trip.

(continued)

BASES

ACTIONS (continued)

A.1

Condition A addresses the situation where the RSW is inoperable. The Required Action is to restore the RSW to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 with T_{avg} < 350°F within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

SR 3.3.4.1 verifies that each required RSW transfer switch performs the required functions. This ensures that if the control room becomes inaccessible, the unit can be placed and maintained in MODE 4 with T_{avg} < 350°F from the RSW. The 24 month Frequency was developed considering it is prudent that these types of surveillances be performed during a unit outage. However, this surveillance is not required to be performed only during a unit outage. This is due to the unit conditions needed to perform the surveillance and the potential for unplanned transients if the surveillance is performed with the reactor at power. Operating experience demonstrates that RSW transfer switches usually pass the surveillance test when performed on the 24 month Frequency.

SR 3.3.4.2

This Surveillance verifies that the RSW communicates controls and indications with Divisions A, B, C, and D of the PMS. Communication is accomplished by use of separate multiplexers for each division. The operator can select the controls and indications available through each PMS division.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.2 (continued)

The Frequency is based on the known reliability of the Functions and the redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.4.3

SR 3.3.4.3 verifies the OPERABILITY of the RSW hardware and software by performing diagnostics to show that operator displays are capable of being called up and displayed to an operator at the RSW. The RSW has several video display units which can be used by the operator. The video display units are identical to that provided in the control room and the operator can display information on the video display units in a manner which is identical to the way the information is displayed in the control room. The operator normally selects an appropriate set of displays based on the particular operational goals being controlled by the operator at the time. Each display consists of static graphical and legend information which is contained within the display processor associated with each video display unit and dynamic data which is updated by the data display system.

The Frequency of 24 months is based on the use of the data display capability in the control room as part of the normal unit operation and the availability of multiple video display units at the RSW. The Frequency of 24 months is based upon operating experience and consistency with control room hardware and software.

SR 3.3.4.4

SR 3.3.4.4 is the performance of a TRIP ACTUATING DEVICE OPERATIONAL TEST (TADOT) every 24 months. This test should verify the OPERABILITY of the reactor trip breakers (RTBs) open and closed indication on the RSW by actuating the RTBs. The Frequency of 24 months was chosen because the RTBs may not be exercised while the facility is at power and is based on operating experience and consistency with the refueling outage.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.
2. Section 7.4.1, "Safe Shutdown."

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.021

Question:

(Section 16.1, Bases References for TSs 3.3.1 and 3.3.2) Reference 7 for TS 3.3.1 and Reference 6 for TS 3.3.2 seem to cite the same document, WCAP-10271-P-A, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," Supplement 2, Revision 1. However the document dates cited in TS 3.3.1 and TS 3.3.2 are not the same (June 1996 and June 1990, respectively). Please correct this discrepancy. The reactor trip system (RTS) and ESFAS instrumentation designs for the AP1000 are different from those addressed in the STS and the AP600. Explain how WCAP-10271-P-A applies to the AP1000 instrumentation test intervals and allowed outage times.

Westinghouse Response:

June 1990 is the correct date for WCAP-10271-P-A, Supplement 2, Revision 1. Reference 7 of Technical Specification (TS) Bases 3.3.1 will be corrected as shown below.

WCAP-10271-P-A, Supplement 2, Revision 1, is applied to the AP1000 as the basis for some of the TS Completion Times. The application of WCAP-10271-P-A follows the template of the Standard Technical Specifications. Although some aspects of the digital systems are different for AP600 and AP1000, the functional design of the AP1000 protection system is the same as that for AP600. WCAP-10271-P-A, Supplement 2, Revision 1, is applicable to the reactor trip and engineered safety features actuated by the protection and safety monitoring system for both the AP1000 and the AP600. The NRC, via a safety evaluation report issued on the Sequoyah Nuclear Plant, Unit 1, Docket, has approved the applicability of the methodologies provided in this WCAP to digital equipment. The AP1000 PRA also provides justification for the TS Completion Times.

Design Control Document (DCD) Revision:

3.3.1 Reactor Trip System (RTS) Instrumentation

REFERENCES

7. WCAP-10271-P-A, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," Supplement 2, Revision 1, June ~~1996~~1990.

PRA Revision:

None

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.11 (continued)

The SR 3.3.1.11 is modified by exempting neutron detectors from response time testing. A Note to the Surveillance indicates that neutron detectors may be excluded from RTS RESPONSE TIME testing. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response.

REFERENCES

1. Chapter 6.0, "Engineered Safety Features."
2. Chapter 7.0, "Instrumentation and Controls."
3. Chapter 15.0, "Accident Analysis."
4. WCAP-14606, "Westinghouse Setpoint Methodology for Protection Systems," April 1996 (nonproprietary).
5. Institute of Electrical and Electronic Engineers, IEEE-603-1991, "IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations," June 27, 1991.
6. 10 CFR 50.49, "Environmental Qualifications of Electric Equipment Important to Safety for Nuclear Power Plants."
7. WCAP-10271-P-A, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," Supplement 2, Revision 1, June 1990.
8. NRC Generic Letter No. 83-27, Surveillance Intervals in Standard Technical Specifications.
9. ESBU-TB-97-01, Westinghouse Technical Bulletin, "Digital Process Rack Operability Determination Criteria," May 1, 1997.
10. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," January 1996.

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.022

Question:

(Section 16.1, TS Section 3.4) Acceptance of TS Section 3.4 requires resolution of RAIs 410.006, 440.036, 440.104, 440.105, 440.106, 440.140, and 471.001. Please resolve these issues and revise the DCD/TSs accordingly.

NOTE: AP1000 RAIs 410.006, 440.036, 440.104, 440.105, 440.106, 440.140, and 471.001 were issued on September 30, 2002 (ADAMS Accession No. ML022680338).

Westinghouse Response:

Of the RAIs listed above, only RAI 440.104 resulted in a change to the AP1000 Technical Specifications. RAI 440.036 resulted in a change to the DCD but not to the Technical Specifications.

Design Control Document (DCD) Revision:

See the responses to RAI 440.104 and 440.036 for the proposed AP1000 DCD and Technical Specification changes.

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 630.023

Question:

A. (Section 16.1, TS 3.4.15) AP1000 RAI 440.036 refers to TS 3.4.3 and TS 3.4.15 and requested a derivation of the proposed low-pressure over-pressure protection (LTOP) arming temperature (275°F), which will also be specified in the pressure-temperature limits report (PTLR). This RAI is for tracking any changes to TS 3.4.15 that may result from the resolution of RAI 440.036. Please resolve this issue and revise the DCD/TSs accordingly.

NOTE: AP1000 RAI 440.036 was issued on September 30, 2002 (ADAMS Accession No. (ML022680338).

B. The Applicability of STS 3.4.12 states the LTOP system is required in "Mode 4 when *any* RCS cold leg temperature is ≤ [275°F]." Please explain why the AP1000 TS 3.4.15 Applicability states "Mode 4 when *all* RCS cold leg temperatures are ≤ 275°F."

C. Why is the RCS vent area of 5.4 square inches a bracketed value?

Westinghouse Response:

A. There is no change to the low-temperature over-pressure protection (LTOP) arming temperature of 275 F as given in AP1000 Technical Specification 3.4.15. See the response to RAI 440.036.

B. The applicability of the AP1000 Technical Specification 3.4.15 will be revised to: "This LCO is applicable in MODE 4 when any RCS cold leg temperature is below 275 F". This is a conservative approach for reactor vessel protection and is consistent with the bases in Standard Technical Specification 3.4.12 (Note that the standard specification itself has "...all RCS cold leg temperatures...").

C. The RCS vent area of 5.4 square inches is in brackets in AP1000 Technical Specification 3.4.12 to indicate that this is preliminary information which will be replaced with plant specific values by the Combined License Applicant. The pressure/temperature limits provided in the DCD are generic curves for the AP1000 reactor vessel design. The Combined License Applicant will develop plant-specific curves during procurement of the reactor vessel. The area of the vent currently given is equivalent to the area of the inlet pipe to the RNS suction relief valve, therefore the capacity of the vent is greater than the flow possible from either the mass or heat input transient while maintaining the RCS pressure less than the minimum of either the pressure/temperature limit curve or 110% of the RNS system design pressure. Once the plant-specific pressure/temperature curves have been developed, the RNS relief valve sizing will be reevaluated to ensure adequate pressure protection during the low temperature over-pressure transients. The vent area will be reevaluated to ensure compatibility with this RNS relief valve size.

Over the life of the plant the reactor vessel material toughness may decrease due to neutron embrittlement. The Combined License Applicant will reevaluate the pressure/temperature limits, if necessary, during the life of the plant using the results of the material surveillance program. The RCS vent area will be reevaluated for compliance each time the pressure/temperature limit curves are revised.

The commitments for the Combined License Applicant to verify plant-specific beltline material properties, develop plant specific pressure/temperature limit curves based on these vessel material properties, and to maintain a reactor vessel material surveillance program are given in DCD section 5.3.6.

Design Control Document (DCD) Revision:

See attached marked-up pages from AP1000 TS 3.4.15.

PRA Revision:

None