TENNESSEE VALLEY AUTHORITY

CHATTANOOGA, TENNESSEE 37401
1630 Chestnut Street Tower II

January 3, 1985

Director of Nuclear Reactor Regulation
Attention: Ms. E. Adensam, Chief
Licensing Branch No. 4
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Ms. Adensam:

In the Matter of the Application of	)	Docket Nos. 50-390
Tennessee Valley Authority	)	50-391

Please refer to your letter to H. G. Parris dated August 22, 1984 which transmitted a set of comments/questions concerning possible discrepancies between the Watts Bar Nuclear Plant (WBN) unit 1 draft Technical Specifications, the WBN Final Safety Analysis Report (FSAR) and the NRC Staff WBN Safety Evaluation Report.

As recommended in the referenced letter, a meeting was held between NRC, TVA and Westinghouse Electric Corporation representatives on September 7, 1984 at the NRC offices in Bethesda, Maryland, to expedite the resolution of these comments/questions and to determine which items require formal responses. The meeting concluded with TVA being requested to provide formal responses to item numbers 2b, 3a, 3b, 4a, 4b, 4c, 4d, 6a, 6b, 8a, 9, 11, 13, 17a, 17b, 18, 25, 27, and 28 of the enclosure to the referenced letter.

Enclosed are responses to those items identified at the September 7, 1984 meeting as requiring a formal reply. Included with several of the responses are associated proposed Technical Specification revisions and/or FSAR revisions to be included in Amendment 55.

In addition, TVA has elected to respond to question number 23 concerning Reactor Coolant System hydrostatic test pressure.

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1/1

Director of Nuclear Reactor Regulation January 3, 1985

If you have any questions concerning this matter, please get in touch with D. B. Ellis at FTS 858-2681.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

J. A. Domer

J. A. Domer
Nuclear Engineer

Sworn to and subscribed before me
this 3rd day of January 1985

Paulette H. White

Notary Public
My Commission Expires 8-24-88

Enclosure
cc: U.S. Nuclear Regulatory Commission (Enclosure)
Region II
Attn: Mr. James P. O'Reilly Administrator
101 Marietta Street, NW, Suite 2900
Atlanta, Georgia 30323

ENCLOSURE

Response to August 22, 1984 letter
from E. Adensam to H. G. Parris

NRC Question

2. Reactor Trip Instrumentation, Table 3.3-1 (page 3/4 3-2)

   b. Item 20, the minimum channels operable for interlock P-10 for Mode 1 conflicts with FSAR Section 7.2.1.1.2. That is, when coming down in power it takes 3 out of 4 P-10 channels to reinstate the intermediate range high neutron flux trip and the low power range neutron flux trip. Item 20 shows 2 out of 4.

Response

Reference: Westinghouse SSPS drawing 1082H70 sheets 1 and 2 for Watts Bar (Attached).

From a safety standpoint, P-10 does two functions: (1) provides input to P-7 which Auto Enables the "At Power" Reactor Trips on 2/4 logic above setpoint -10 percent, and (2) Auto Enables the "Low Power" Reactor Trips (including Source Range high flux trip coincident w/P-6) on 3/4 logic below setpoint - 10 percent . Additionally, above P-10 a manual block of the "Low Power" Reactor Trips can be performed, however, this does not serve any safety function.

It should be noted that the bistables for P-10 have an energized output below the setpoint and switch when above the setpoint (i.e., to Auto Enable the "Low Power" Trips 3 bistables must be energized).

The way the Technical Specifications are currently written the input to P-7 is covered appropriately under P-7 functional unit 20.b. However, the Auto Enable of the "Low Power" Reactor Trips is not adequately covered. See the attached marked up Technical Specification pages for the required changes discussed below.

Technical Specifications - Changes

Table 3.3-1 Functional Unit 20.e (TS page 3/4 3-4)

CHANNELS TO TRIP should be 3, not 2. Three bistables must be energized to Auto Enable the "Low Power" Reactor Trips.

Table 3.3-1 Functional Unit 20.e and ACTION STATEMENT 12 (TS page 3/4 3-4 and TS page 3/4 3-8)

MINIMUM CHANNELS OPERABLE should be 4, not 3. Three channels are required to Auto Enable, thus 4 must be OPERABLE to meet single failure criteria. ACTION STATEMENT 12 has been added to reflect appropriate actions to different conditions. With less than 4 channels OPERABLE and the "Low Power" Reactor Trips blocked a plant shutdown below the P-10 setpoint (10 percent) is not warranted since the capability to enable the "Low Power" Reactor Trips may be lost. Since the P-10 bistables must be energized to enable the "Low Power" Reactor Trips, removing power from the bistables will not reinstate the trips. With less than 4 channels OPERABLE and the "Low Power" Reactor Trips not blocked, any P-10 failure will not block the "Low Power" Reactor Trips since it also takes coincident manual blocking (4 separate handswitches) to defeat them. Thus, the appropriate action is to restore the inoperable channels to OPERABLE status before blocking the "Low Power" Reactor Trip.

Table 3.3-1 Functional Unit 20.e (TS page 3/4 3-4) and Table 4.3-1 Functional unit 20.e (TS page 3/4 3-13)

APPLICABLE MODES should have mode 2 deleted. There is no consequence of being in mode 2 with P-10 operable. The Auto Enable of the "Low Power" Reactor Trips and the input to P-7 will take place at 10-percent Reactor power which is mode 1. And, as discussed above, the "Low Power" Reactor Trips once enabled cannot be blocked without manual action. A failure which would cause a P-10 input to P-7 in modes 2 and below could only enable the "At Power" Reactor Trips and thus has no adverse safety effect. Any P-10 malfunction that could make the Source Range detectors inoperable in mode 2 and below would be readily detectable via MCR indications and alarms and would be handled in accordance with Limiting Condition for Operation 3.3.1 (item 6 table 3.3-1) covering the Source Range detectors.

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
18. Turbine Trip					
a. Low Fluid Oil Pressure	3	2	2	1####	7#
b. Turbine Stop Valve Closure	4	4	4	1####	11#
19. Safety Injection Input from ESF	2	1	2	1, 2	9
20. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2	1	2	2##	8
b. Low Power Reactor Trips Block, P-7					
P-10 Input	4	2	3	1	8
or					
P-13 Input	2	1	2	1	8
c. Power Range Neutron Flux, P-8	4	2	3	1	8
d. Power Range Neutron Flux, P-9	4	2	3	1	8
e. Power Range Neutron Flux, P-10	4	3 ~~2~~	4 ~~3~~	1 ~~1, 2~~	12 ~~8~~
f. Turbine Impulse Chamber Pressure, P-13	2	1	2	1	8

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FINAL DRAFT

TABLE 3.3-1 (Continued)

ACTION STATEMENTS (Continued)

ACTION 9 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within 6 hours; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.1.1, provided the other channel is OPERABLE.

ACTION 10 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the Reactor trip breakers within the next hour.

ACTION 11 - With the number of OPERABLE channels less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or reduce power to below 50% RATED THERMAL POWER within the next 6 hours.

ACTION 12 - With the number of OPERABLE channels less than the Minimum Channels OPERABLE requirement and

1) With the "Low Power" Reactor Trips blocked, immediately restore the inoperable channels to OPERABLE status.

or

2) With the "Low Power" Reactor Trips <u>not</u> blocked, restore the inoperable channels to OPERABLE status prior to blocking the "Low Power" Reactor Trips.

The provisions of Specification 3.0.3 are not applicable.

TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
20. Reactor Trip System Interlocks (Continued)						
d. Power Range Neutron Flux, P-9	N.A.	R (4)	M (8)	N.A.	N.A.	1
e. Power Range Neutron Flux, P-10	N.A.	R (4)	M (8)	N.A.	N.A.	~~1, 2~~ 1
f. Turbine Impulse Chamber Pressure, P-13	N.A.	R	M (8)	N.A.	N.A.	1
21. Reactor Trip Breaker	N.A.	N.A.	N.A.	M (7,11)	N.A.	1,2,3*,4*,5*
22. Automatic Trip and Interlock Logic	N.A.	N.A.	N.A.	N.A.	M (7)	1,2,3*,4*,5*

NRC Question

3. Reactor Trip System Instrumentation Response Times, Table 3.3-2 (page 3/4 3-9).

   a. Table 15.2-1 of the FSAR shows a reactor trip in 2 seconds for overtemperature Delta-T. This table lists this as 3 seconds. Please resolve this discrepancy.

Response

The 2 second delay shown in FSAR Table 15.2-1 occurs after a trip signal is generated by the overtemperature Delta-T protection circuit and is included in the analysis to account for delays associated with the opening of the reactor trip breakers, decay of voltage on the control rod drive mechanism gripper coil and other electronic delays. This 2 second delay is only a portion of the delay associated with the overtemperature Delta-T circuit which is modeled in the analysis. FSAR Table 15.1-3 shows a total of 6 seconds delay modeled in the FSAR analysis. Other delays amounting to 4 seconds which are not shown in Table 15.2-1 but which are included in the analysis account for the lag associated with the RTD manifold and the RTD itself among other things. Technical specifications define reactor trip system response time as the time from when the monitored parameter is at the setpoint until the rods are free to fall into the core. Excluded by this definition is the lag associated with the RTD manifold (approximately 2 seconds). The correct technical specification response time for the overtemperature Delta-T circuit then is 4 seconds.

NOTE: The technical specifications have already been revised to reflect the correct response times for the overtemperature and overpower Delta - T channels.

NRC Question

3. Reactor Trip System Instrumentation Response Times, Table 3.3-2 (page 3/4 3-9)

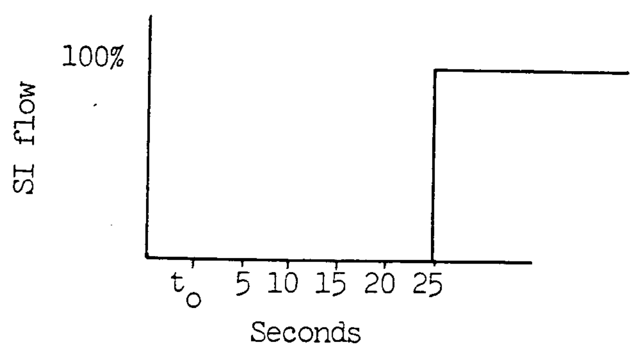
   b. Section 15.3.1.2 of the FSAR assumed a SI delay of 28 seconds, yet the TS response time is listed as 27 seconds. Please explain. Furthermore, it should be noted that 15.4.1.1.5 states that the time to reach the SI setpoint and to generate an SI signal is 1.5 seconds. How do these values correspond to Table 15.4-1 of the FSAR which lists an SI signal occurring as soon as .85 seconds and pump injection 25 seconds later.

Response

Section 15.3.1.2 of the FSAR correctly states that for the small break LOCA a delay of 25 seconds was included in the analysis before SI flow was initiated. This 25 second delay starts when the monitored parameter reaches the trip setpoint and ends with the initiation of full SI flow at the end of 25 seconds. During the 25 second delay, no high pressure SI flow is assumed available. For large break LOCA, Table 15.4-1 of the FSAR shows 0.85 seconds for the monitored parameter to reach the trip setpoint, the SI signal has not been generated at this point. Then, 25 seconds later SI flow is initiated. The 25 second delay accounts for SI signal generation, diesel start time and pump start time as described below.

The 27 seconds in the technical specifications is consistent with the 25 seconds in the LOCA analysis due to the conservative assumption of no SI flow for 25 seconds. In reality SI flow starts well before the 25 seconds assumed in the analysis. The figures below provide a comparison of the analysis assumption vs actual performance.

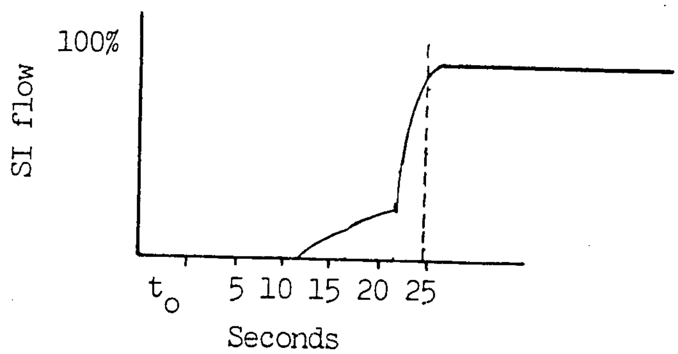
Safety Analysis



t_o - accident starts

25 - full SI flow is available

Actual Performance



t_o - accident starts

2 - SI signal is generated

12 - diesel is up to speed and charging pumps start

17 - charging pumps at full flow, SI pumps start

22 - SI and charging pumps at full flow, RHR pumps start

27 - Full SI flow

By taking no credit for SI flow before 25 seconds the accident analyses are consistent with the technical specification requirements for the emergency core cooling system.

Section 15.4.1.1.5 of the FSAR lists an SI signal generation time of 1.5 seconds to actuate containment ventilation isolation. Only a portion of the SI circuitry is common to the containment ventilation isolation valves and the ECCS. The portion of the circuitry which is specific to the containment ventilation isolation valves is less complex than that associated with the ECCS. Therefore the 1.5 second response time is not necessarily more restrictive than the 2.0 seconds used for the ECCS. Both response times must be verified in accordance with the technical specifications.

NRC Question

4. ESFAS Instrumentation, Table 3.3-3 (page 3/4 3-26)

   a. Item 8F, the initiation of auxiliary feedwater on a trip of all main feedwater pumps, states that the minimum number of channels to be operable is one per MFW pump. How does this satisfy the single failure criterion?

Response

The initiation of auxiliary feedwater on a trip of all main feedwater pumps is an anticipatory signal. As such, it is not required to meet single failure criteria. As documented in the results part of FSAR section 15.2.8, "Loss of Normal Feedwater," auxiliary feedwater is initiated on low-low steam generator level with a 60 second response time. FSAR section 15.2.9, "Loss-of-Offsite Power to the Station Auxiliaries (Station Blackout)," states that auxiliary feedwater initiation is the same as that for a loss of feedwater analysis. For accidents, auxiliary feedwater is initiated by the safety injection signal.

NRC Question

4. ESFAS Instrumentation, Table 3.3-3 (page 3/4 3-26)

   b. Justify that it is appropriate to block out steam line SI below P-12. Consider the consequences of a main steam line break outside containment.

Response

TVA's response to FSAR Question Q212.40 adequately addresses this concern. Attached is a revised response to Q212.40 resulting from modifications to plant and operating procedures to account for the removal of the boron injection tank, TMI modifications, and cold overpressure protection. These revisions will be reflected in a later amendment to the FSAR (Amendment 55).

212.40 Question
(6.3)

When shutting down or starting up the plant, the automatic safety injection signal is blocked to preclude unwanted actuation of these systems. Describe the alarms available to alert the operator to a failure in the primary or secondary system during this phase of operation and the time frame available to mitigate the consequences of such an accident. Justify the time frame available.

Response

The sequence of events associated with shutdown are described below. The procedures associated with startup will be the same except they will be in reverse order. The startup procedures are not presented here to avoid unnecessary duplication. This response is divided into three parts (a, b, and c) in which, a) summarizes the operator instructions for performing the isolation of the ECCS equipment, b) describes the operator actions necessary for activating the ECCS equipment, and c) discusses the safety significance of locking out ECCS equipment.

a) Operator Instructions During Shutdown

(i) At 540°F, the operator blocks the high steam flow SI signal. At 1900 psig, the operator manually blocks the automatic safety injection signal from the pressurizer level and pressure transmitters. All other SI signals including containment high pressure and high steamline differential pressure are armed and will actuate safety injection if their setpoints are exceeded. Manual safety injection actuation is also available.

(ii) At 1700 psig, the operator closes and gags isolations valves from the UHI accumulators.

(iii) At 1000 psig, the operator closes, removes power, and tags the SI accumulator isolation valves. At 350°F he also locks out and tags the safety injection pumps and one charging pump. At this time, one charging pump and 2 LH residual heat removal pumps would be available from either automatic or manual SI actuation.

(iiii) At less than 400 psig and 350°F, the operator aligns the Residual Heat Removal System. The valves in the line from the RWST are closed.

b) Operator Actions During Shutdown

(i) Between 1900 psig and 1000 psig, the ECCS system, except for UHI, can either be actuated automatically by the high containment pressure signal, steamline differential pressure, or manually by the operator.

(ii) Between 1000 psig and 400 psig, a portion of the ECCS system can be actuated automatically (on containment high pressure or high steamline differential pressure) or manually by the operator. The equipment that can be energized are 2 residual heat removal and 1 HH charging pumps. The operator would have to reinstitute power at the motor control centers to the cold leg accumulator isolation valves and the other pumps and remove the gags and open the UHI accumulator isolation valves.

(iii) Below 400 psig the system is in the RHR cooling mode. The RHR system would have to be realigned as per plant startup procedure. Place all safeguards systems valves in the required positions for plant operation and place the safety injection, centrifugal charging and residual heat removal pumps along with SI and UHI accumulators in ready. The operator would then manually actuate SI.

c) Safety Significance During Shutdown

LOCA

Comparing plant cooldown and heatup, the limiting case for a LOCA would be during a plant cooldown rather than a plant heatup because the core decay heat generation would be higher. The ECCS analysis presented in the Watts Bar Final Safety Analysis Report conforms to the Acceptance Criteria of 10 CFR 50.46 so that initiation of the LOCA is at 102% of full licensed power rating and corresponding RCS conditions. Some of the reasons why the analysis presented in the plant SAR would be more limiting than a LOCA during shutdown are: 1) A LOCA initiated during shutdown would have reduced decay heat generation since the reactor would have been at zero power for an extended period of time, 2) the core stored energy during shutdown would be reduced due to the RCS isothermal condition at a reduced temperature, and 3) the energy content of the RCS would be lower. An evaluation of the safety significance of a LOCA during shutdown is presented below.

(i) Between 1900 psig and 1000 psig, all the safety equipment in the ECC system except the UHI is aligned for safety injection with the exception of the pressurizer SI and steam flow SI signals disarmed. During this time period, the operator is monitoring and manually controlling the pressurizer pressure, level, and RCS temperature per the plant cooldown procedure. Also, the technical specifications impose minimum temperature requirements as a function of pressure on the operator to avoid exceeding NDT limitations. The operator, as a matter of course, has available the pressurizer pressure/level, and RCS temperature measurements on the control board strip chart recorders. For large LOCA's sufficient mass and energy would be released to the containment to automatically actuate the safety injection when the containment high pressure setpoint is reached. The operator would be alerted at this time of the occurrence of a LOCA by the following safety related indications:

1) loss of pressurizer level

2) rapid decrease of RCS pressure

3) containment pressure increase

4) sump water level increase

In addition to the above, the following indications are normally available to the operator at the control board:

1) radiation alarms inside containment

2) accumulator water levels decreased off scale and pressure decreasing

3) ECCS system valve and pump position and status lights in ECCS energized indication. Annunciators will light as safeguards equipment becomes energized.

Any leakage of the RHR system piping would be expected to occur when the system is initially pressurized at 400 psia. The RCS is at this time under manual control by the reactor operator. The reactor operator is, at this time, monitoring the pressurizer level and the RCS loop pressure so that any significant leakage from the RHR system would be immediately detected. If leakage is detected, then the operator would isolate the RHR system and identify the location and cause. Since the decay heat generation 4 hours after shutdown is about 1.2% of full power, the RCS fluid temperature is at about 350°F, and the core stored energy is essentially removed, the operator would have ample time to isolate the RHR loop.

Non-LOCA Accidents

Although startup and shutdown are transient events and therefore accidents are not to be considered coincidentally, the following protection would be afforded the plant for a secondary-side pipe rupture.

Safety injection actuation on low pressurizer pressure will be manually blocked when NSSS pressure falls below P-11 (1900 psig). Safety injection actuation on high steam flow coincident with low steamline pressure will be manually blocked when Tav falls below P-12 (Lo-Lo Tav). If a steamline rupture occurs while both of these safety injection actuation signals are blocked, steamline isolation will occur on high steam flow/lo-lo Tav coincident (note: lo-lo-Tav must exist before safety injection can be blocked). If steam line isolation stops the steam flow, no further protection would be required. If, after steamline isolation, the blowdown continues, safety injection will be actuated on steamline differential pressure.

Prior to cooldown, the boron concentration is increased to at least the cold shutdown boron concentration. Likewise, on quick recovery from a reactor trip or during unanticipated delays during startup, the boron concentration is increased to the hot standby xenon-free condition. These measures plus the Technical Specification shutdown margin requirement assures the steamline rupture return to power from hot, zero power shown in the FSAR is higher than the case where the safety injection actuation is manually blocked on Low Steamline Pressure/High Steamline Flow and Low Pressurizer Pressure/Low Pressurizer Level.

NRC Question

4. ESFAS Instrumentation, Table 3.3-3 (page 3/4 3-26)

   c. Justify that it is appropriate not to require SI LOCA protection on high containment pressure in mode 4.

Response

TVA's response to FSAR Question Q212.40 adequately addresses this concern. Attached is a revised response to Q212.40 resulting from modifications to plant and operating procedures to account for the removal of the boron injection tank, TMI modifications, and cold overpressure protection. These revisions will be reflected in a later amendment to the FSAR (Amendment 55).

NRC Question

4. ESFAS Instrumentation, Table 3.3-3 (page 3/4 3-26)

   d. Justify that manual actuation of steam line isolation is not needed in mode 4 to deal with a SGTR.

Response

Resolution being pursued on a generic basis.

NRC Question

6. ESF Response Times, Table 3.3-5 (page 3/4 3-32)

   a. FSAR Table 15.1-3 lists the delay times associated with SG level-high-high assumed in the safety analyses as 2.0 seconds for turbine trip and feedwater isolation. The TS list these items (8.a and 8.b) as 2.5 and 11 seconds respectively. Please resolve this.

Response

The delay times listed in technical specification table 3.3-5 for items 8.a and 8.b are correct. Attached are approved Chapter 15 FSAR revisions which reflect a response time of 2.5 seconds for turbine trip and 11 seconds for feedwater isolation following steam generator water level - high-high. This brings the safety analysis, the FSAR and the technical specifications into accord. These revisions will be reflected in a later amendment to the FSAR (Amendment 55).

TABLE 15.1-3 (Continued)

TRIP POINTS AND TIME DELAYS TO TRIP

ASSUME IN ACCIDENT ANALYSES

Trip Function	Limiting Trip Point Assumed In Analysis	Time Delays (Second)
Low reactor coolant flow (from loop flow detectors)	87% loop flow	1.0
Undervoltage Trip	70%	1.5
Turbine Trip	Not applicable	1.0
Low-Low steam generator level	6% of narrow range span between o and 20% nominal load, and increasing linearly to 49% of span at 100% of nominal load	2.0
High-High steam generator level, Turbine Trip	83% of narrow range level span	2.5
High-High steam generator level, Feedwater Isolation	83% of narrow range level span	11.0

NRC Question

6. ESF Response Times, Table 3.3-5 (page 3/4 3-32)

   b. Several response times in the table cannot be verified by information in the Chapter 15 analyses. Please provide additional information so that we can verify the Technical Specification values for the response times for all of the actions listed in the table except for reactor trip and those actions associated with steam generator level low-low and high-high. You need only consider those actions that were assumed to occur in the accident analyses.

Response

The response times listed in Table 3.3-5 have been reviewed. As a result of this review, several revisions to Table 3.3-5 are necessary. (See the attached marked-up technical specifications pages.)

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TABLE 3.3-5

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
1. Manual Initiation	
a. Safety Injection (ECCS)	N.A.
b. Containment Spray	N.A.
c. Phase "A" Isolation	N.A.
d. Phase "B" Isolation	N.A.
e. Ventilation Isolation	N.A.
f. Steam Line Isolation	N.A.
g. Feedwater Isolation	N.A.
h. Auxiliary Feedwater	N.A.
i. Essential Raw Cooling Water	N.A.
j. Control Room Isolation	N.A.
k. Containment Air Return Fan	N.A.
l. Component Cooling Water	N.A.
m. Start Diesel Generators	N.A.
n. Reactor Trip	N.A.
2. Containment Pressure-High	
a. Safety Injection (ECCS)	$\leq 27^{(1)}/12^{(5)}$
1) Reactor Trip	≤ 2
2) Feedwater Isolation	~~$\leq 8^{(3)}$~~
3) Containment Isolation-Phase "A"(6)	$\leq 18^{(2)}/28^{(1)}$
4) Containment Ventilation Isolation	~~N.A.~~ $\leq 5.5^{(2)}$
5) Auxiliary Feedwater Pumps	$\leq 60^{(10)}$
6) Essential Raw Cooling Water	$\leq 65^{(2)}/75^{(1)}$
7) Control Room Isolation	N.A.
8) Component Cooling Water	$\leq 43^{(2)}/45^{(1)}$
9) Start Diesel Generators	~~≤ 10~~ ≤ 12
3. Pressurizer Pressure-Low	
a. Safety Injection (ECCS)	$\leq 27^{(1)}/12^{(5)}$
1) Reactor Trip	≤ 2
2) Feedwater Isolation	~~$\leq 8^{(3)}$~~
3) Containment Isolation-Phase "A"(6)	$\leq 18^{(2)}/28^{(1)}$
4) Containment Ventilation Isolation	~~N.A.~~ $\leq 5.5^{(2)}$

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TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
3. Pressurizer Pressure-Low (Continued)	
5) Auxiliary Feedwater Pumps	≤ 60[10]
6) Essential Raw Cooling Water	≤ 65[2]/75[1]
7) Control Room Isolation	N.A.
8) Component Cooling Water	~~≤ 43[2]/45[1]~~
9) Start Diesel Generators	~~≤ 10~~ ≤ 12
4. Differential Pressure Between Steam Lines-High	
a. Safety Injection (ECCS)	≤ 22[4]/12[5]
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 8[3]
3) Containment Isolation-Phase "A"[6]	≤ 18[2]/28[1]
4) Containment Ventilation Isolation	N.A.
5) Auxiliary Feedwater Pumps	≤ 60[10]
6) Essential Raw Cooling Water	≤ 65[2]/75[1]
7) Control Room Isolation	N.A.
8) Component Cooling Water	~~≤ 43[2]/45[1]~~
9) Start Diesel Generators	~~≤ 10~~ ≤ 12
5. Steam Flow in Two Steam Lines - High Coincident with T_{avg}--Low-Low	
a. Safety Injection (ECCS)	≤ 24[4]/14[5]
1) Reactor Trip (from SI)	≤ 4
2) Feedwater Isolation	≤ 10[3]
3) Containment Isolation-Phase "A"[6]	≤ 20[2]/30[1]
4) Containment Ventilation Isolation	N.A.
5) Auxiliary Feedwater Pumps	≤ 60[10]
6) Essential Raw Cooling Water	≤ 67[2]/77[1]
7) Control Room Isolation	N.A.
8) Component Cooling Water	~~≤ 43[2]/45[1]~~
9) Start Diesel Generators	~~≤ 10~~ ≤ 15
b. Steam Line Isolation	≤ 7

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TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
6. Steam Flow in Two Steam Lines-High Coincident with Steam Line Pressure-Low	
a. Safety Injection (ECCS)	$\leq 12^{(5)}/22^{(4)}$
1) Reactor Trip	≤ 2
2) Feedwater Isolation	$\leq 8^{(3)}$
3) Containment Isolation-Phase "A"(6)	$\leq 18^{(2)}/28^{(1)}$
4) Containment Ventilation Isolation	N.A.
5) Auxiliary Feedwater Pumps	$\leq 60^{(10)}$
6) Essential Raw Cooling Water	$\leq 65^{(2)}/75^{(1)}$
7) Control Room Isolation	N.A.
8) Component Cooling Water	$\leq 43^{(2)}/45^{(1)}$
9) Start Diesel Generators	~~≤ 10~~ ≤ 12
b. Steam Line Isolation	≤ 7
7. Containment Pressure--High-High	
a. Containment Spray	$\leq \cancel{58}\ 50^{(2)}$
b. Containment Isolation-Phase "B"	$\leq 65^{(2)}/75^{(1)}$
c. Steam Line Isolation	≤ 7
d. Containment Air Return Fans	≤ 660
8. Steam Generator Water Level--High-High	
a. Turbine Trip	≤ 2.5
b. Feedwater Isolation	$\leq 11^{(3)}$
9. Steam Generator Water Level - Low-Low	
a. Motor-driven Auxiliary Feedwater Pumps	$\leq 60^{(7)(1)}$
b. Turbine-driven Auxiliary Feedwater Pumps	$\leq 60^{(8)}$
10. RWST Level-Low Coincident with Containment Sump Level-High and Safety Injection	
Automatic Switchover to Containment Sump	≤ 250
11. Loss-of-Offsite Power	
Auxiliary Feedwater Pumps	$\leq 60^{(10)}$
12. Trip of All Main Feedwater Pumps	
Auxiliary Feedwater Pumps	$\leq 60^{(10)}$

NRC Question

8. Condensate Storage Tank, 3/4 7.1.3 (page 3/4 7-6)

   a. The FSAR states that the AFWS is designed to deliver 40°F to 120°F water. What was assumed in the safety analyses for the CST water temperature? Justify why the Watts Bar Technical Specifications do not require such a specification.

Response

The auxiliary feedwater (AFW) system is designed to deliver water in the range of 40°F to 120°F. This is consistent with the safety analyses. The AFW system has two sources of water: the condensate storage tank (CST) and the essential raw cooling water (ERCW) system.

The ERCW system is a raw water system that has the Tennessee River as its source. The river temperature varies between 40°F and 85°F seasonally. The actual temperature from this source would be slightly higher because the AFW pumps take suction from the ERCW discharge header downstream of the various heat exchangers.

The CST is located outside of the turbine building. The temperature of the tank can be expected to be approximately at the daily average ambient air temperature. The temperature of the tank would not change rapidly in response to changes in ambient air temperature because of the large mass of water (minimum volume is 200,000 gallons and maximum tank capacity is 397,000 gallons). The tank volume is regularly recirculated through the condenser and condensate demineralizers for chemistry control. This process also has the effect of forcing the temperature of the tank towards the temperature in the condenser (approximately 100°F).

In summary, the AFW water temperature will be between 40°F and 120°F either because of nature (in the case of ERCW) or because of nature and operating practices (in the case of CST).

NRC Question

9. Plant Systems, Turbine Cycle Valves, B 3/4.7.1.1 (page B3/4 7-1). What is the basis for the equation that derives the reduced reactor trip setpoints whenever there are inoperable safety valves? Is there an analysis to support this equation?

Response

The principle applied in sizing the safety valves is that the capacity of the safety valves is based upon the turbine maximum design loading capability. This principle is applied in sizing the safety valves on a wide range of Westinghouse PWR designs (2, 3, and 4 loop plants of various power ratings). With this sizing, Westinghouse PWRs have satisfied design criteria of preventing overpressurization of the secondary system.

The basis for the technical specification equation is to limit the maximum steady-state steam flow from the NSSS to that value which can be relieved by the operable safety valves. This equation directly applies the above principle to reduced safety valve capacity for a particular unit. If a safety valve becomes inoperable, the relieving capacity for a steam generator steam line is diminished by that amount. The setpoint reduction limits the maximum steady state and transient steam generation rates to a value consistent with the operable safety valve capacity. It is assumed that this is comparable to an analysis for a PWR at a lower power rating (e.g., the capacity of a 4-loop PWR (3425 MWT) and a 3-loop PWR (2785 MWT).

Based upon this, no other analysis is considered necessary.

NRC Question

11. Technical specification 3.4.3 (page 3/4 4-9) requires a maximum pressurizer level of 92 percent in mode 1, 2, and 3. Please justify this value since this requirement does not appear to be inclusive of the stated capability to borate to cold shutdown without letdown (Q212.93 page 8) which requires a 800 ft^3 bubble.

Response

The 92 percent high pressurizer level trip protects the system against a water solid overpressure accident that could be caused by the start of a reactor coolant pump in a loop that has the secondary side 50°F hotter than the primary side. The 8-percent steam bubble can accommodate the thermal expansion.

The boration needed to compensate for cooldown and xenon decay effects on reactivity requires the addition of 800 cubic feet of 12-percent boric acid. The need to borate is not immediate; it can be accomplished during the cooldown period and during xenon decay.

The normal pressurizer level during power operation is 60 percent. The normal level drops to 25 percent on a reactor trip because the average reactor coolant system temperature drops from 588°F to 557°F. These levels are maintained by the automatic control system and controlled by plant operating and maintenance procedures. Technical specification 6.8.1 establishes the administrative control program for plant procedures. Changes to the pressurizer level control program cannot be made without the review required by 10 CFR Part 50.59. Operation outside of the normal programmed level would be considered an off-normal event and remedied by operator action.

A pressurizer level of 25 percent leaves more than 1300 cubic feet of steam space for boration. In addition, cooldown to the residual heat removal system cut-in point results in a coolant contraction of more than 1800 cubic feet. The normal operation condition of the plant ensures that sufficient steam space exists in the reactor coolant system to facilitate boration to offset xenon decay and cooldown reactivity effects. Changes to the pressurizer level operating program are controlled. Operation outside the programmed level is limited to brief off-normal events by procedures required by technical specification 6.8.1.

NRC Question

13. The response to question 212.99 states that "To preclude the potential for spurious (RHR) isolation after the RCS is opened, plant procedures require that electric power be locked out to both suction isolation valves and that only one RHR pump be operated when the RCS is open." Justify the omission of these requirements from the Technical Specifications.

Response

The plant procedures used to operate during MODE 6 addresses the situation outlined in FSAR question 212.99. TVA believes that this is a proper method of handling this concern. The procedures have sufficient detail to preclude spurious residual heat removal pump suction isolation and subsequent pump failure. Technical specification 6.8.1 establishes administrative controls for the establishment, implementation, and maintenance of procedures used to control plant operation.

The concept of requiring technical specifications for each and every detail of plant operation has a hidden safety cost. As the Technical Specifications become more detailed with minor concerns, the major safety concerns are reduced in importance. During its review of Portland General Electric Company's Trojan Nuclear Plant, the Atomic Safety and Licensing Board addressed the statuatory requirements on deciding those matters that should be subject to a technical specification. The Appeal Board stated:

> From the foregoing, it seems quite apparent that there is neither a statuatory nor a regulatory requirement that every operational detail set forth in an applicant's safety analysis report (or equivalent) be subject to a technical specification, to be included in the license as an absolute condition of operation which is legally binding upon the licensee unless and until changed with specific Commission approval. Rather, as best as we can discern it, the contemplation of both the ACT and the regulations is that technical specifications are to be reserved for those matters as to which the imposition of rigid conditions or limitations upon reactor operation is deemed necessary to alleviate the possibility of an event giving rise to an immediate threat to the public health and safety.

TVA agrees with the Appeal Board position. TVA believes that the use of operating procedures to address the concerns raised in FSAR question 212.99 is the most appropriate method.

NRC Question

17. PORV Setpoint Figure 3.4-4 (page 3/4 4-36)

Supporting information for the PORV setpiont curve was provided in a letter of June 7, 1984. The PORV setpoint was determined as a function of pressure for actuation of one charging pump without letdown and startup of one reactor coolant pump. Section 5.2.2.10.2 of RESAR-414 was referenced.

a. RESAR-414 recommends that a bubble be present in the pressurizer for startup of a reactor coolant pump if no other reactor coolant pump is in operation. Justify the omission of this recommendation from the technical specifications.

Response

The recommendation contained in RESAR-414 to have a bubble present when starting a reactor coolant pump is made in accordance with good engineering practices to minimize the magnitude of potential pressure surges. This is a conservative operating practice which will enhance safe plant operation. However, circumstances may arise in which it is necessary or desirable to start a reactor coolant pump with the reactor coolant system solid. To ensure this capability, the cold overpressure systems were nominally designed and analyzed assuming reactor coolant pump start under solid conditions. Technical specifications were written in accordance with the design and analyses and reflect acceptable operating practices. The technical specifications as written reflect the limiting reactor coolant pump starting criteria.

The Watts Bar general operation procedures and system operating procedures have several notes and precautions warning against starting a reactor coolant pump without a steam bubble in the pressurizer. The operator training program provides simulator training using these procedures. The need for a steam bubble during the start of a reactor coolant pump is addressed in the training. The procedures that are used for operation are controlled by the requirements of technical specification 6.8.1. TVA believes that this method is the most appropriate for addressing NRC's concern.

NRC Question

17. PORV Setpoint Figure 3.4-4 (page 3/4 4-36)

Supporting information for the PORV setpiont curve was provided in a letter of June 7, 1984. The PORV setpoint was determined as a function of pressure for actuation of one charging pump without letdown and startup of one reactor coolant pump. Section 5.2.2.10.2 of RESAR-414 was referenced.

b. Justify the omission of other low temperature overpressurization events from consideration in development of the PORV setpoint curve (i.e., inadvertent pressurizer heater actuation and SI pump actuation).

Response

The transients included in the cold overpressure analysis were identified by Westinghouse as bounding transients during the performance of an evaluation of cold overpessure events. A report entitled, "Pressure Mitigation System Transient Analysis Results," was prepared by Westinghouse in July 1977. A supplement of the same title was prepared in September 1977.

Concerning SI pump operation, the cold overpressure analysis considered only the operation of a charging pump. To prevent the possibility of a mass input from a safety injection pump occurring, the technical specifications require that all safety injection pumps be inoperable in those modes for which cold overpressure is a concern (proposed revisions to technical specification 3.5.3 attached). In addition, surveillance requirement 4.5.3.2 should be revised to permit testing of the safety injection pumps and filling of the cold leg accumulators whenever the pump must be incapable of causing a cold overpressure event (proposed revisions to surveillance requirement 4.5.3.2 attached).

FINAL DRAFT

3/4.5.3 ECCS SUBSYSTEMS - T_{avg} < 350°F

LIMITING CONDITION FOR OPERATION

3.5.3 As a minimum, one ECCS subsystem comprised of the following shall be OPERABLE:

a. One OPERABLE centrifugal charging pump,#

b. One OPERABLE RHR heat exchanger,

c. One OPERABLE RHR pump, and

d. An OPERABLE flow path capable of taking suction from the refueling water storage tank upon being manually realigned and transferring suction to the containment sump during the recirculation phase of operation.

APPLICABILITY: MODE 4.

ACTION:

a. With no ECCS subsystem OPERABLE because of the inoperability of either the centrifugal charging pump or the flow path from the refueling water storage tank, restore at least one ECCS subsystem to OPERABLE status within 1 hour or be in COLD SHUTDOWN within the next 20 hours.

b. With no ECCS subsystem OPERABLE because of the inoperability of either the RHR heat exchanger or RHR pump, restore at least one ECCS subsystem to OPERABLE status or maintain the Reactor Coolant System T_{avg} less than 350°F by use of alternate heat removal methods.

c. In the event the ECCS is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date. The current value of the usage factor for each affected Safety Injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

A maximum of one centrifugal charging pump ~~and one Safety Injection pump~~ shall be OPERABLE whenever the temperature of one or more of the RCS cold legs is less than or equal to 350°F.

FINAL DRAFT

SURVEILLANCE REQUIREMENTS

4.5.3.1 The ECCS subsystem shall be demonstrated OPERABLE per the applicable requirements of Specification 4.5.2.

4.5.3.2 All charging pumps and Safety Injection pumps, except the above allowed OPERABLE pumps, shall be demonstrated inoperable at least once per 12 hours whenever the temperature of one or more of the RCS cold legs is less than or equal to 350°F by verifying that the pumps are in the pull-to-lock position ~~and~~ and/or the motor circuit breakers are tagged out, or the pump(s) is isolated from the RCS by a manually closed valve or by a motor-operated valve with the valve breaker tagged.

NRC Question

18. Relief Valves (Section 3/4.4.9, page 3/4 4-10)

It is the staff's understanding that your steam generator tube rupture analysis presented in Chapter 15 of your FSAR relied on the availability and operability of the pressurizer power operated relief valves (PORVs) and the steam generator atmospheric dump valves (ADVs) for depressurization and cooldown in order to limit offsite doses to within 10 CFR 100 guideline values. Similarly, your cooldown evaluation in FSAR section 5.4.7 performed to show compliance with BTP RSB 5-1 relied on the availability and operability of the PORVs and ADVs to provide the necessary depressurization and cooldown function. Your proposed technical specifications however, appear to be inconsistent with your FSAR assumptions in that they allow the PORV to be taken out of service for an indefinite period of time and, on the other hand, they do not contain an operability requirement for the steam generator ADVs. Please demontrate how you comply with the requirements of 10 CFR 50.36 regarding how your technical specifications for the PORV were derived from the FSAR safety analyses. Specifically, we believe it is necessary to show that the steam generator tube rupture criteria and the RSB 5-1 criteria can be met assuming inoperable PORVs and ADVs consistent with your proposed technical specifications. Otherwise, you should demonstrate that your technical specification is consistent with the FSAR analyses.

Response

Technical specification 3.4.4 for the pressurizer power operated relief valves has been revised to address the above concerns. The ACTION statements distinguish between inoperability due to excessive seat leakage and other causes. The valves can be closed and blocked indefinitely to stop seat leakage as long as there is reasonable assurance that the valves can be opened when needed. The surveillance requirements provide this reasonable assurance. Plant shutdown within a specified time is required whenever the valves cannot be opened.

Automatic or remote manual operation of the steam generator power operated relief valves is not necessarily required. As noted in response to FSAR question 212.93, manual operation of the valves can be accomplished. In fact, one of the special natural circulation tests performed at Sequoyah Nuclear Plant simulated a loss of all ac power. Cooldown was initiated and controlled for 2 hours using manual operation of these valves. In addition, the steam dump valves could be used (remote or manual operation) if the condenser was available.

NRC Question

23. (Bases) 2.1. Reactor Coolant System Pressure (page B 2-2)

This section states that the entire RCS is hydrotested at 3107 psig which is 125 percent of the system's design pressure. The staff notes that 125% of design pressure is 1.25 times 2500 psia = 3125 psia - 15 psia = 3110 psig.

The staff notes that this issue involves an insignificant difference of 3 psi. However, we recommend that this editorial change be made.

Response

The technical specification value specified for the RCS hydrostatic test pressure should be 3107 psig.

TVA has reviewed its records for the initial cold hydrostatic pressure test. The minimum acceptable test pressure was listed as 3107 psig. The test has been completed with an acceptance criteria on pressure of 3107 psig. The technical specification value must not be different than the acceptance criteria of a test that is part of the quality assurance records for the plant.

Further, TVA disagrees with the method used to calculate value of 3110 psig. The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Codes specify that the hydrostatic tests be performed at 125 percent of design pressure. The design documents for the reactor pressure vessel list the design pressure as 2485 psig. Standard code convention is to multiply 2485 psig times 1.25 to get a pressure of 3107 psig. The purpose of the test is to ensure that the vessel can withstand the appropriate differential pressure. Since the atmospheric pressure is relatively constant and it is the pressure outside the vessel, gauge pressure is the appropriate pressure to use for the test.

NRC Question

25. In response to Question 31.150 on high energy line breaks causing control systems failures, you stated that the rod control system will not withdraw rods as a result of a steam line break because the neutron detectors are qualified for two minutes for an adverse environment and that the reactor will trip on overpower Delta-T within that time. However, since this postulated accident may occur in mode 3, it would seem that this reactor trip should be operable in this mode. If the overpower Delta-T trip is not available in mode 3, then the time to trip the reactor on some other variable may exceed the two minute limitation and rod withdrawal may occur. Please resolve this.

Response

For a postulated high energy line break in Mode 3, no credit would be taken for reactor trip since the reactor is already shutdown. Therefore, neither the overpower Delta-T nor any other reactor trip need be operable for this event.

A rod withdrawal occurring as a result of a high energy line break affecting the neutron detectors in Mode 3 is extremely unlikely for the following reasons:

1. Typically, in Mode 3 the rod control system would be selected to a mode other than automatic, manual for example. Automatic rod withdrawal could occur only in the presence of a failure of the selector switch.

2. In Mode 3 the turbine generator is not operating. The rod control system automatically blocks rod withdrawal (in the automatic mode) if turbine impulse pressure is below the equivalent of 15-percent power. With the turbine not operating, this interlock would be active and automatic rod withdrawal prohibited. Automatic rod withdrawal could occur only in the presence of a failure in this rod block circuit.

3. The neutron detector input to the rod control system is compared to turbine impulse pressure (used as the reference power level). This circuit will call for rod motion only in the presence of a difference between the rate of change of the two input signals. For example, if the turbine underwent a rapid runback, turbine power would be changing rapidly with respect to nuclear power. The rod control system would call for rod insertion to match the rates. In the event of a high energy line break in Mode 3, the only rod motion which could result from operation of this circuit is rod insertion. This is due to turbine power indicating 0 percent due to the turbine being offline. Nuclear power cannot be changing negatively with respect to this 0% power reference, therefore automatic rod withdrawal would be called for only as a result of a failure in this circuit.

To summarize, at least 2 and typically 3 failures would be required before automatic rod withdrawal in the prescribed conditions could occur in Mode 3.

NRC Question

27. Table 3.3-1, Reactor Trip Instrumentation (page 3/4 3-2). For rod withdrawal accident at subcritical conditions, the staff is under the impression that reactor trip is initiated by the power range neutron flux trip. However, the power range neutron flux trip needs only to be operable in modes 1 and 2 according to the Technical Specifications. Please explain this apparent discrepancy. If your explanation takes credit for either the intermediate range or source range trips, then the setpoint methodology will have to be amended to reflect this.

Response

Although the accident analyses assume reactor trip following rod withdrawal from subcritical conditions occurs as a result of operation of the power range trips, it is acceptable to take credit (in the Technical Specifications) for operation of the source range. The source range trip would provide protection sooner than would the power range hence the safety analyses remain bounding. The source range provides redundancy and hence meets single failure criteria. The technical specification requires two source ranges and associated trip circuitry to be operable in shutdown modes whenever the reactor trip breakers are closed in keeping with single failure assumptions. Westinghouse is of the opinion that source range operability during shutdown conditions satisfies protection requirements for those modes.

The setpoint study is acceptable as is to allow credit to be taken for the source ranges. Referring to Table 3-19 of the setpoint study, all instrument uncertainties associated with the source range are identified. The channel statistical allowance, that is, the maximum expected measurement error as determined by statistical methods, for the source range is 10.8 percent of instrument span. Given a trip setpoint of 1×10^5 cps, and an instrument span of 1×10^6 cps, the largest actual flux level expected at the time of trip is 2.1×10^5 cps. This is well below the upper limit of the source range. An analysis performed with a trip setpoint as high as 8.9×10^5 cps would be conservative with respect to the safety analysis and would be acceptable from an instrumentation aspect. Therefore, an actual flux level of 2.1×10^5 cps is acceptable.

The anlaysis for an uncontrolled rod cluster control assembly bank withdrawal event was performed at hot zero power with an effective multiplication factor of 1.0. As stated in FSAR section 15.2.1.2:

> This initial temperature yields a larger fuel-water heat transfer coefficient, larger specific heats, and a less negative (smaller absolute magnitude) doppler coefficient all of which tend to reduce the doppler feedback effect thereby increasing the neutron flux peak. The reactivity condition assumed also results in the worst nuclear power transient.

For the conditions described above, the reactor would be considered in Mode 2 according to the Standard Technical Specifications. The Watts Bar Technical Specifications are consistent with the limiting analyses.

If the NRC staff is concerned about bank withdrawals in Modes 4 or 3, then the technical specifications afford protection by requiring two source range trip channels to be operable. The transient would also be less severe than the case described above. The reactor coolant temperature would be lower, improving the parameters described above. The reactor would be at least 1-percent Delta-K/K subcritical as specified by Standard Technical Specifications. The trip setpoint on the source range channel is approximately six decades lower than the power range low setpoint assumed in the safety analysis.

A safety analysis trip limit of 35 percent power range was assumed. This value corresponds to approximately 1×10^{-4} amps on the intermediate range detector. The trip setpoint on the source range detector is 1×10^{5} counts per second. This value corresponds to approximately 5×10^{-10} amps on the intermediate range detector. The upper limit on the source range detector is 1×10^{6} counts per second and the lower limit is 1 count per second. The total channel error has been calculated to be 10.8 percent of span. This is less than one decade. The source range trip setpoint of 1×10^{5} counts per second ensures that even with the worst case error the trip will occur before the source range detector goes offscale high.

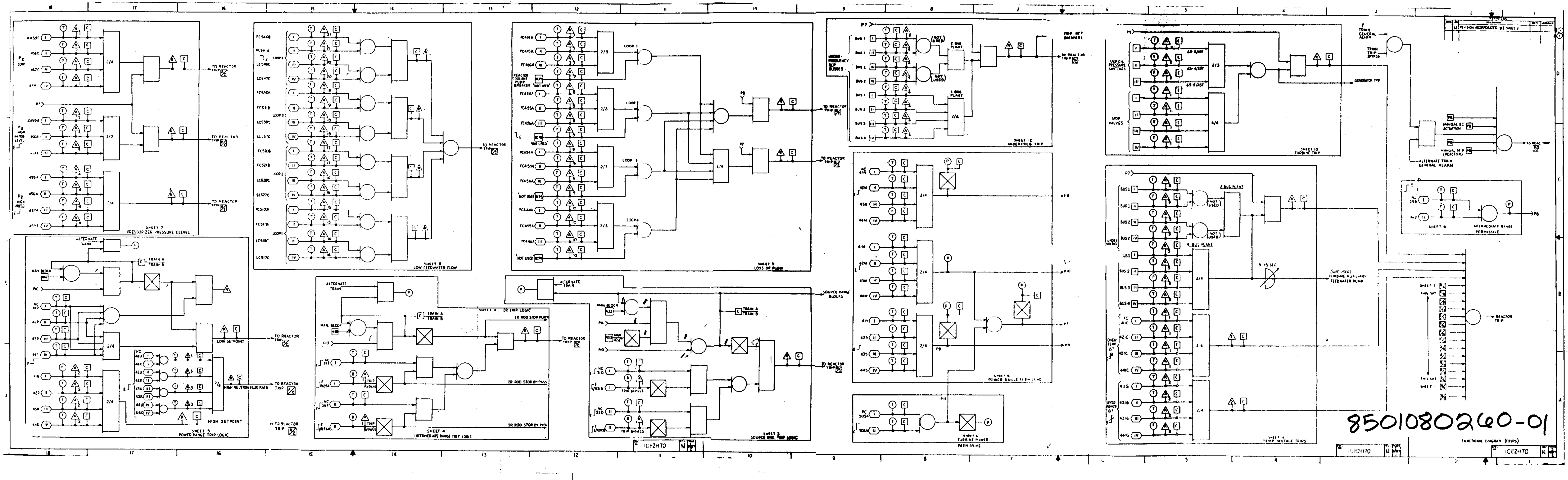
The technical specifications are consistent with the limiting safety analysis for an uncontrolled rod cluster control assembly bank withdrawal event. The technical specifictions also provide protection for less limiting bank withdrawals in Modes 3 and 4 by requiring that two source range trip channels be operable. The source range trip setpoint is consistent with calculated channel error and is approximately six decades more conservative than the limiting safety analysis assumed setpoint.

NRC Question

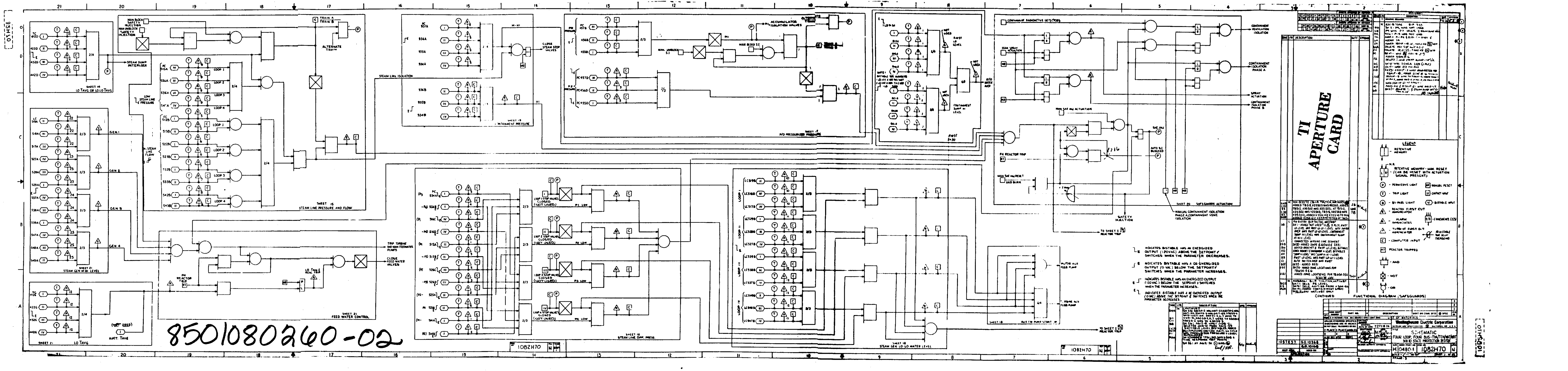
28. Reactor Coolant System Hot Shutdown 3.4.1.3 (page 3/4 4-3). Technical specification 3.4.1.3 permits operation in mode 4 with one RHR loop in operation. Justify that the consequences of an inadvertent control rod withdrawal event with one RHR loop in operation in mode 4 would be bounded by the FSAR analysis which assumes two reactor coolant pumps in operation in mode 2. In your evaluation, consider the effect of nonuniform flow distribution through the core on minimum DNBR.

Response

Resolution being pursued on a generic basis.



TI
APERTURE
CARD



LO TAVG OR LO LO TAVG
STEAM DUMP INTERLOCK
STEAM GEN HI HI LEVEL
LO TAVG
FEED WATER CONTROL
CLOSE FEED WATER VALVES
STEAM LINE PRESSURE AND FLOW
CONTAINMENT PRESSURE
CLOSE STEAM STOP VALVES
PZR PRESSURIZER PRESSURE
ACCUMULATOR ISOLATION VALVES
CONTAINMENT RADIOACTIVE DETECTORS
CONTAINMENT VENTILATION ISOLATION
CONTAINMENT ISOLATION PHASE A
SPRAY ACTUATION
CONTAINMENT ISOLATION PHASE B
SAFEGUARDS ACTUATION
SAFETY INJECTION
STEAM LINE DIFF. PRESS
STEAM GEN LO LO WATER LEVEL
AUX FW PUMP START
TI APERTURE CARD
LEGEND
FUNCTIONAL DIAGRAM (SAFEGUARDS)
CONTINUED
LIST OF MATERIALS
Westinghouse Electric Corporation
22FEB74
SCHEMATIC
FOUR LOOP, FOUR BUS-TVA/TEN/WAT/WBT
SOLID STATE PROTECTION SYSTEM
1057E57
G.O.10368
G.O.10168
H 04804 1082H70 N
1082H70
8501080260-02