UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

October 31, 1990

Docket No. 50-328

Mr. Oliver D. Kingsley, Jr.
Senior Vice President, Nuclear Power
Tennessee Valley Authority
6N 38A Lookout Place
1101 Market Street
Chattanooga, Tennessee 37402-2801

Dear Mr. Kingsley:

SUBJECT: REACTOR PROTECTION SYSTEM UPGRADES AND ENHANCEMENTS (TAC 75844) (TS 89-27) - SEQUOYAH NUCLEAR PLANT, UNIT 2

The Commission has issued the enclosed Amendment No. 132 to Facility Operating License No. DPR-79 for the Sequoyah Nuclear Plant, Unit 2. This amendment is in response to your applications dated January 24, April 25, May 15, and October 2, 1990.

This amendment modifies the Sequoyah Nuclear Plant, Unit 2, Technical Specifications (TSs). The changes revise the definition section; the Specifications 2.2.1, 3/4.3.1.1, and 3/4.3.2.1; and the associated bases for the revised specifications to reflect reactor protection system (RPS) upgrades and enhancements which were implemented on Unit 2 during the current Unit 2 Cycle 4 refueling outage.

The specific TSs which were revised are the following: (1) add definition 1.6.c and an acronym for Rated Thermal Power; (2) add or revise parameters in Tables 2.2-1, 3.3-1, 3.3-2, 3.3-3, 3.3-4, 3.3-5, 4.3-1, and 4.3-2; (3) add footnotes or action statements in Tables 3.3-1, 3.3-3, and 3.3-5; and (4) delete outdated footnotes and unused action statements in Tables 3.3-3, 3.3-4, 4.3-1 and 4.3-2. These changes reflect rack drift allowables for the Eagle-21 digital process protection system; the incorporation of the environmental allowance modifier, the trip time delay feature, and the median signal selector; the removal of the resistance temperature detector bypass manifolds; the addition of a new steamline break protection logic; the implementation of engineered safety features actuation system enhancements; and the deletion of out-of-date footnotes and unused action statements. The basis for this amendment is discussed in the enclosed Safety Evaluation.

Your applications also proposed changes for the Sequoyah Unit 1 TSs. These changes were issued by letter dated May 16, 1990 during the Unit 1 Cycle 4 refueling outage. The RPS upgrades and enhancements associated with the proposed TS changes were implemented at Unit 1 during this outage.

The Notice of Issuance for this amendment will be included in the Commission's Bi-Weekly Federal Register Notice.

In your letter dated May 10, 1990, you committed to (1) report Eagle-21 System hardware, design software, and maintenance problems encountered during the startup of Unit 1 from the current Unit 1 Cycle 4 refueling outage; (2) submit, for Unit 1 operating Cycle 5, six-month reports discussing the operations of the Eagle-21 System from the start of Unit 1 operating Cycle 5; and (3) submit software configuration and system modifications, prior to implementation, not consistent with the staff-approved Revision 3 of the final Eagle-21 System Verification and Validation Report for Sequoyah, which was submitted by letter dated May 8, 1990. You committed to submit the first report within 30 days of Unit 1 reaching approximately 100 percent power. This commitment was extended to Unit 2 in the telephone discussion with your staff on October 4, 1990.

The enclosed Safety Evaluation is based on a review and evaluation of Westinghouse Electric Corporation proprietary documents. As a precaution, we recommend that your staff and Westinghouse review the enclosed report for proprietary material. Unless you notify this office, by telephone, within 10 days of the date of this letter, and submit a written application to withhold the information contained therein within 30 days, in accordance with 10 CFR 2.790(a), a copy of this letter and the enclosed information will be placed in the NRC Public Document Room. Such application must be consistent with the requirements of 10 CFR 2.790(b)(1).

The reporting and/or recordkeeping requirements contained in this letter affect fewer than ten respondents; therefore, OMB clearance is not required under P.L. 96-511.

Sincerely,

Jack N. Donohew

Jack N. Donohew, Project Manager
Project Directorate II-4
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. Amendment No. 132 to
   License No. DPR-79
2. Safety Evaluation

cc w/enclosures:
See next page

In your letter dated May 10, 1990, you committed to (1) report Eagle-21 System hardware, design software, and maintenance problems encountered during the startup of Unit 1 from the current Unit 1 Cycle 4 refueling outage; (2) submit, for Unit 1 operating Cycle 5, six-month reports discussing the operations of the Eagle-21 System from the start of Unit 1 operating Cycle 5; and (3) submit software configuration and system modifications, prior to implementation, not consistent with the staff-approved Revision 3 of the final Eagle-21 System Verification and Validation Report for Sequoyah, which was submitted by letter dated May 8, 1990. You committed to submit the first report within 30 days of Unit 1 reaching approximately 100 percent power. This commitment was extended to Unit 2 in the telephone discussion with your staff on October 4, 1990.

The enclosed Safety Evaluation is based on a review and evaluation of Westinghouse Electric Corporation proprietary documents. As a precaution, we recommend that your staff and Westinghouse review the enclosed report for proprietary material. Unless you notify this office, by telephone, within 10 days of the date of this letter, and submit a written application to withhold the information contained therein within 30 days, in accordance with 10 CFR 2.790(a), a copy of this letter and the enclosed information will be placed in the NRC Public Document Room. Such application must be consistent with the requirements of 10 CFR 2.790(b)(1).

The reporting and/or recordkeeping requirements contained in this letter affect fewer than ten respondents; therefore, OMB clearance is not required under P.L. 96-511.

Sincerely,

JN Donohew Jr

Jack N. Donohew, Project Manager
Project Directorate II-4
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. Amendment No. 132 to
   License No. DPR-79
2. Safety Evaluation

cc w/enclosures:
See next page

NOTE: The proposed Unit 2 TS Page 2-9 was corrected to be same as that for Unit 1.

OFC	:PDII-4/LA	:PDII-4/PM	:OGC	:PDII-4/DD	:PDII-4/D	:
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AMENDMENT NO. 132 FOR SEQUOYAH UNIT NO. 2 - DOCKET NO. 50-328
DATED: October 31, 1990

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

TENNESSEE VALLEY AUTHORITY

DOCKET NO. 50-328

SEQUOYAH NUCLEAR PLANT UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 132
License No. DPR-79

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The applications for amendment by Tennessee Valley Authority (the licensee) dated January 24, April 25, May 15, and October 2, 1990, comply with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the applications, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraph 2.C.(2) of Facility Operating License No. DPR-79 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 132, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Frederick J. Hebdon

Frederick J. Hebdon, Director
Project Directorate II-4
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical Specifications

Date of Issuance: October 31, 1990

ATTACHMENT TO LICENSE AMENDMENT NO. 132

FACILITY OPERATING LICENSE NO. DPR-79

DOCKET NO. 50-328

Revise the Appendix A Technical Specifications by removing the pages identified below and inserting the enclosed pages. The revised pages are identified by the captioned amendment number and contain marginal lines indicating the area of change. Overleaf pages, marked with an "*", are provided to maintain document completeness.

REMOVE.	INSERT
1-2	1-2
1-5	1-5*
1-6	1-6
2-4	2-4*
2-5	2-5
2-6	2-6
---	2-7
2-7	2-8
2-8	2-9
2-9	2-10
2-10	2-11
---	2-12
B 2-4	B 2-4
B 2-5	B 2-5
B 2-6	B 2-6
---	B 2-7
B 2-7	B 2-8
3/4 3-1	3/4 3-1*
3/4 3-2	3/4 3-2
3/4 3-3	3/4 3-3
---	3/4 3-3a
3/4 3-4	3/4 3-4*
3/4 3-5	3/4 3-5
3/4 3-6	3/4 3-6
3/4 3-7	3/4 3-7
3/4 3-8	3/4 3-8
3/4 3-9	3/4 3-9
3/4 3-10	3/4 3-10
3/4 3-11	3/4 3-11
3/4 3-12	3/4 3-12
3/4 3-13	3/4 3-13
3/4 3-14	3/4 3-14*
3/4 3-15	3/4 3-15
3/4 3-16	3/4 3-16
3/4 3-17	3/7 3-17*
3/4 3-18	3/4 3-18
3/4 3-19	3/4 3-19
---	3/4 3-19a
3/4 3-20	3/4 3-20*
3/4 3-21	3/4 3-21
3/4 3-21a	3/4 3-21a
3/4 3-22	3/4 3-22
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---	3/4 3-23a

REMOVE	INSERT
3/4 3-24	3/4 3-24
3/4 3-25	3/4 3-25
3/4 3-26	3/4 3-26
3/4 3-27	3/4 3-27
3/4 3-27a	3/4 3-27a
---	3/4 3-27b
3/4 3-28	3/4 3-28
3/4 3-30	3/4 3-30
3/4 3-31	3/4 3-31
3/4 3-33a	3/4 3-33a
3/4 3-34	3/4 3-34
3/4 3-35	3/4 3-35*
3/4 3-36	3/4 3-36
3/4 3-37	3/4 3-37
3/4 3-38	3/4 3-38
B 3/4 3-1	B 3/4 3-1

CHANNEL FUNCTIONAL TEST

1.6 A CHANNEL FUNCTIONAL TEST shall be:

a. Analog channels - the injection of a simulated signal into the channel as close to the sensor as practicable to verify OPERABILITY including alarm and/or trip functions.

b. Bistable channels - the injection of a simulated signal into the sensor to verify OPERABILITY including alarm and/or trip functions.

c. Digital channels - the injection of a simulated signal into the channel as close to the sensor input to the process racks as practicable to verify OPERABILITY including alarm and/or trip functions.

CONTAINMENT INTEGRITY

1.7 CONTAINMENT INTEGRITY shall exist when:

a. All penetrations required to be closed during accident conditions are either:

   1) Capable of being closed by an OPERABLE containment automatic isolation valve system, or

   2) Closed by manual valves, blind flanges, or deactivated automatic valves secured in their closed positions, except as provided in Table 3.6-2 of Specification 3.6.3.

b. All equipment hatches are closed and sealed,

c. Each air lock is in compliance with the requirements of Specification 3.6.1.3,

d. The containment leakage rates are within the limits of Specification 3.6.1.2, and

e. The sealing mechanism associated with each penetration (e.g., welds, bellows or O-rings) is OPERABLE.

CONTROLLED LEAKAGE

1.8 CONTROLLED LEAKAGE shall be that seal water flow supplied to the reactor coolant pump seals.

CORE ALTERATION

1.9 CORE ALTERATION shall be the movement or manipulation of any component within the reactor pressure vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATION shall not preclude completion of movement of a component to a safe conservative position.

OPERATIONAL MODE - MODE

1.19 An OPERATIONAL MODE (i.e., MODE) shall correspond to any one inclusive combination of core reactivity condition, power level and average reactor coolant temperature specified in Table 1.1.

PHYSICS TESTS

1.20 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and 1) described in Chapter 14.0 of the FSAR, 2) authorized under the provisions of 10 CFR 50.59, or 3) otherwise approved by the Commission.

PRESSURE BOUNDARY LEAKAGE

1.21 PRESSURE BOUNDARY LEAKAGE shall be leakage (except steam generator tube leakage) through a non-isolable fault in a Reactor Coolant System component body, pipe wall or vessel wall.

PROCESS CONTROL PROGRAM (PCP)

1.22 The PROCESS CONTROL PROGRAM shall contain the current formula sampling, analysis tests, and determinations to be made to ensure that the processing and packaging of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Part 20, 10 CFR Part 71, and federal and state regulations and other requirements governing the disposal of radioactive wastes.

PURGE - PURGING

1.23 PURGE or PURGING is the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

QUADRANT POWER TILT RATIO

1.24 QUADRANT POWER TILT RATIO shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater. With one excore detector inoperable, the remaining three detectors shall be used for computing the average.

RATED THERMAL POWER (RTP)

1.25 RATED THERMAL POWER (RTP) shall be a total reactor core heat transfer rate to the reactor coolant of 3411 MWt.

REACTOR TRIP SYSTEM RESPONSE TIME

1.26 The REACTOR TRIP SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until loss of stationary gripper coil voltage.

REPORTABLE EVENT

1.27 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

SHIELD BUILDING INTEGRITY

1.28 SHIELD BUILDING INTEGRITY shall exist when:

a. The door in each access opening is closed except when the access opening is being used for normal transit entry and exit.

b. The emergency gas treatment system is OPERABLE.

c. The sealing mechanism associated with each penetration (e.g., welds, bellows or O-rings) is OPERABLE.

SHUTDOWN MARGIN

1.29 SHUTDOWN MARGIN shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming all full length rod cluster assemblies (shutdown and control) are fully inserted except for the single rod cluster assembly of highest reactivity worth which is assumed to be fully withdrawn.

SITE BOUNDARY

1.30 The SITE BOUNDARY shall be that line beyond which the land is not owned, leased, or otherwise controlled by the licensee (see figure 5.1-1).

2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

2.1.1 The reactor trip system instrumentation and interlocks setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2-1.

APPLICABILITY: As shown for each channel in Table 3.3-1.

ACTION:

With a reactor trip system instrumentation or interlock setpoint less conservative than the value shown in the Allowable Values column of Table 2.2-1, declare the channel inoperable and apply the applicable ACTION statement requirement of Specification 3.3.1 until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not Applicable	Not Applicable
2. Power Range, Neutron Flux	Low Setpoint - $\leq$ 25% of RATED THERMAL POWER	Low Setpoint - $\leq$ 27.4% of RATED THERMAL POWER
	High Setpoint - $\leq$ 109% of RATED THERMAL POWER	High Setpoint - $\leq$ 111.4% of RATED THERMAL POWER
3. Power Range, Neutron Flux, High Positive Rate	$\leq$ 5% of RATED THERMAL POWER with a time constant $\geq$ 2 seconds	$\leq$ 6.3% of RATED THERMAL POWER with a time constant $\geq$ 2 seconds
4. Power Range, Neutron Flux, High Negative Rate	$\leq$ 5% of RATED THERMAL POWER with a time constant $\geq$ 2 seconds	$\leq$ 6.3% of RATED THERMAL POWER with a time constant $\geq$ 2 seconds
5. Intermediate Range, Neutron Flux	$\leq$ 25% of RATED THERMAL POWER	$\leq$ 30% of RATED THERMAL POWER
6. Source Range, Neutron Flux	$\leq 10^5$ counts per second	$\leq 1.3 \times 10^5$ counts per second
7. Overtemperature ΔT	See Note 1	See Note 3
8. Overpower ΔT	See Note 2	See Note 4
9. Pressurizer Pressure--Low	$\geq$ 1970 psig	$\geq$ 1964.8 psig
10. Pressurizer Pressure--High	< 2385 psig	$\leq$ 2390.2 psig
11. Pressurizer Water Level--High	$\leq$ 92% of instrument span	$\leq$ 92.7% of instrument span
12. Loss of Flow	$\geq$ 90% of design flow per loop*	$\geq$ 89.4% of design flow per loop*

*Design flow is 91,400 gpm per loop.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
13. Steam Generator Water Level--Low-Low		
a. RCS Loop ΔT Equivalent to Power $\leq$ 50% RTP	RCS Loop ΔT variable input $\leq$ 50% RTP	RCS Loop ΔT variable input $\leq$ trip setpoint +2.5% RTP
Coincident with Steam Generator Water Level--Low-Low (Adverse)	$\geq$ 15.0% of narrow range instrument span	$\geq$ 14.4% of narrow range instrument span
and Containment Pressure (EAM)	$\leq$ 0.5 psig	$\leq$ 0.6 psig
or		
Steam Generator Water Level--Low-Low (EAM)	$\geq$ 10.7% of narrow range instrument span	$\geq$ 10.1% of narrow range instrument span
With		
A time delay (T_s) if one Steam Generator is affected	$\leq T_s$ (Note 5)	$\leq (1.01)T_s$ (Note 5)
or		
A time delay (T_m) if two or more Steam Generators are affected	$\leq T_m$ (Note 5)	$\leq (1.01)T_m$ (Note 5)

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
b. RCS Loop ΔT Equivalent to Power > 50% RTP		
Coincident with		
Steam Generator Water Level--Low-Low (Adverse)	≥ 15.0% of narrow range instrument span	≥ 14.4% of narrow range instrument span
and		
Containment Pressure (EAM)	≤ 0.5 psig	≤ 0.6 psig
or		
Steam Generator Water Level--Low-Low (EAM)	≥ 10.7% of narrow range instrument span	≥ 10.1% of narrow range instrument span
14. Deleted		
15. Undervoltage-Reactor Coolant Pumps	≥ 5022 volts-each bus	≥ 4739 volts - each bus
16. Underfrequency-Reactor Coolant Pumps	≥ 56 Hz - each bus	≥ 55.9 Hz - each bus
17. Turbine Trip		
A. Low Trip System Pressure	≥ 45 psig	≥ 43 psig
B. Turbine Stop Valve Closure	≥ 1% open	> 1% open
18. Safety Injection Input from ESF	Not Applicable	Not Applicable

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
19. Intermediate Range Neutron Flux, P-6, Enable Block Source Range Reactor Trip	> 1 x 10^{-5}% of RATED THERMAL POWER	> 6 x 10^{-6}% of RATED THERMAL POWER
20. Power Range Neutron Flux (not P-10) Input to Low Power Reactor Trips Block P-7	< 10% of RATED THERMAL POWER	< 12.4% of RATED THERMAL POWER
21. Turbine Impulse Chamber Pressure - (P-13) Input to Low Power Reactor Trips Block P-7	< 10% Turbine Impulse Pressure Equivalent	< 12.4% Turbine Impulse Pressure Equivalent
22. Power Range Neutron Flux - (P-8) Low Reactor Coolant Loop Flow, and Reactor Trip	< 35% of RATED THERMAL POWER	< 37.4% of RATED THERMAL POWER
23. Power Range Neutron Flux - (P-10) - Enable block of Source, Intermediate, and Power Range (low setpoint) Reactor Trips	> 10% of RATED THERMAL POWER	> 7.6% of RATED THERMAL POWER
24. Reactor Trip P-4	Not Applicable	Not Applicable
25. Power Range Neutron Flux - (P-9) - Blocks Reactor Trip for Turbine Trip Below 50% Rated Power	< 50% of RATED THERMAL POWER	< 52.4% of RATED THERMAL POWER

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

NOTATION

NOTE 1: Overtemperature $\Delta T \left(\frac{1 + \tau_4 S}{1 + \tau_5 S}\right) \leq \Delta T_o \{K_1 - K_2 \left(\frac{1 + \tau_1 S}{1 + \tau_2 S}\right)[T - T'] + K_3(P-P') - f_1(\Delta I)\}$

where: $\frac{1 + \tau_4 S}{1 + \tau_5 S}$ = Lag compensator on measured ΔT

τ_4, τ_5 = Time constants utilized in the lead-lag controller for ΔT, τ_4 = 12 secs, τ_5 = 3 secs

ΔT_o = Indicated ΔT at RATED THERMAL POWER

K_1 $\leq$ 1.15

K_2 = 0.011

$\frac{1 + \tau_1 S}{1 + \tau_2 S}$ = The function generated by the lead-lag controller for T_{avg} dynamic compensation

τ_1, & τ_2 = Time constants utilized in the lead-lag controller for T_{avg}, τ_1 = 33 secs., τ_2 = 4 secs.

T = Average temperature °F

T' $\leq$ 578.2°F (Nominal T_{avg} at RATED THERMAL POWER)

K_3 = 0.00055

P = Pressurizer pressure, psig

P' = 2235 psig (Nominal RCS operating pressure)

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

NOTATION (Continued)

NOTE 1: (Continued)

S = Laplace transform operator. sec^{-1}

and $f_1(\Delta I)$ is a function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

(i) for $q_t - q_b$ between - 29 percent and + 5 percent $f_1(\Delta I) = 0$ (where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $qt + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER).

(ii) for each percent that the magnitude of $(q_t - q_b)$ exceeds -29 percent, the ΔT trip setpoint shall be automatically reduced by 1.50 percent of its value at RATED THERMAL POWER.

(iii) for each percent that the magnitude of $(q_t - q_b)$ exceeds +5 percent, the ΔT trip setpoint shall be automatically reduced by 0.86 percent of its value at RATED THERMAL POWER.

NOTE 2: Overpower $\Delta T \left(\frac{1 + \tau_4 S}{1 + \tau_5 S}\right) \leq \Delta T_o \{K_4 - K_5 \left(\frac{\tau_3 S}{1 + \tau_3 S}\right) T - K_6[T - T''] - f_2(\Delta I)\}$

where: $\frac{1 + \tau_4 S}{1 + \tau_5 S}$ = as defined in Note 1

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

NOTATION (Continued)

NOTE 2: (Continued)

τ_4, τ_5	=	as defined in Note 1
ΔT_o	=	as defined in Note 1
K_4	$\leq$	1.087
K_5	=	0.02/°F for increasing average temperature and 0 for decreasing average temperature
$\frac{\tau_3 S}{1 + \tau_3 S}$	=	The function generated by the rate-lag controller for T_{avg} dynamic compensation
τ_3	=	Time constant utilized in the rate-lag controller for T_{avg}, τ_3 = 10 secs.
K_6	=	0.0011 for $T > T''$ and $K_6 = 0$ for $T \leq T''$
T	=	as defined in Note 1
T"	=	Indicated T_{avg} at RATED THERMAL POWER (Calibration temperature for ΔT instrumentation, $\leq$ 578.2°F)
S	=	as defined in Note 1
$f_2(\Delta I)$	=	0 for all ΔI

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

NOTATION (Continued)

NOTE 3: The channel's maximum trip setpoint shall not exceed its computed trip point by more than 1.9 percent ΔT span.

NOTE 4: The channel's maximum trip setpoint shall not exceed its computed trip setpoint by more than 1.7 percent ΔT span.

NOTE 5: Trip Time Delay - Steam Generator Water Level--Low-Low

$$T_s = \{(-0.00583)(P)^3 + (0.735)(P)^2 - (33.560)(P) + 649.5\}\{0.99\}$$

$$T_m = \{(-0.00532)(P)^3 + (0.678)(P)^2 - (31.340)(P) + 589.5\}\{0.99\}$$

Where:

P = RCS Loop ΔT Equivalent to Power (% RTP), $P \leq 50\%$ RTP

T_s = Time delay for Steam Generator Water Level--Low-Low Reactor Trip, one Steam Generator affected.

T_m = Time delay for Steam Generator Water Level--Low-Low Reactor Trip, two or more Steam Generators affected.

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1 As a minimum, the reactor trip system instrumentation channels and interlocks of Table 3.3-1 shall be OPERABLE with RESPONSE TIMES as shown in Table 3.3-2.

APPLICABILITY: As shown in Table 3.3-1.

ACTION:

As shown in Table 3.3-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1.1 Each reactor trip system instrumentation channel and interlock shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations for the MODES and at the frequencies shown in Table 4.3-1.

4.3.1.1.2 The logic for the interlocks shall be demonstrated OPERABLE prior to each reactor startup unless performed during the preceeding 92 days. The total interlock function shall be demonstrated OPERABLE at least once per 18 months during CHANNEL CALIBRATION testing of each channel affected by interlock operation.

4.3.1.1.3 The REACTOR TRIP SYSTEM RESPONSE TIME of each reactor trip function shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least one logic train such that both logic trains are tested at least once per 36 months and one channel per function such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip function as shown in the "Total No. of Channels" column of Table 3.3.1.

TABLE 3.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Manual Reactor Trip	2	1	2	1, 2, and *	1
2. Power Range, Neutron Flux	4	2	3	1, 2	$2^{\#}$
3. Power Range, Neutron Flux High Positive Rate	4	2	3	1, 2	$2^{\#}$
4. Power Range, Neutron Flux, High Negative Rate	4	2	3	1, 2	$2^{\#}$
5. Intermediate Range, Neutron Flux	2	1	2	1, 2, and *	3
6. Source Range, Neutron Flux					
A. Startup	2	1	2	$2^{\#\#}$, and *	4
B. Shutdown	2	0	1	3, 4 and 5	5
7. Overtemperature ΔT					
Four Loop Operation	4	2	3	1, 2	$6^{\#}$
8. Overpower ΔT					
Four Loop Operation	4	2	3	1, 2	$6^{\#}$
9. Pressurizer Pressure-Low	4	2	3	1, 2	$6^{\#}$
10. Pressurizer Pressure--High	4	2	3	1, 2	$6^{\#}$
11. Pressurizer Water Level--High	3	2	2	1, 2	$6^{\#}$

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
12. Loss of Flow - Single Loop (Above P-8)	3/loop	2/loop in any operating loop	2/loop in each operating loop	1	6#
13. Loss of Flow - Two Loops (Above P-7 and below P-8)	3/loop	2/loop in two operating loops	2/loop in each operating loop	1	6#
14. Main Steam Generator Water Level--Low-Low					
A. Steam Generator Water Level--Low-Low (Adverse)	3/Stm. Gen.	2/Stm. Gen. in any operating Stm. Gen	2/Stm. Gen. in each operating Stm. Gen.	1,2	9#
B. Steam Generator Water Level--Low-Low (EAM)	3/Stm. Gen.	2/Stm. Gen. in any operating Stm. Gen.	2/Stm. Gen. in each operating Stm. Gen.	1,2	9#
C. RCS Loop ΔT	4 (1/loop)	2	3	1,2	10#
D. Containment Pressure (EAM)	4	2	3	1,2	11#
15. Deleted.					

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
16. Undervoltage-Reactor Coolant Pumps	4-1/bus	2	3	1	$6^{\#}$
17. Underfrequency-Reactor Coolant Pumps	4-1/bus	2	3	1	$6^{\#}$
18. Turbine Trip					
A. Low Fluid Oil Pressure	3	2	2	1	$6^{\#}$
B. Turbine Stop Valve Closure	4	4	4	1	$6^{\#}$
19. Safety Injection Input from ESF	2	1	2	1, 2	12
20. Reactor Trip Breakers					
A. Startup and Power Operation	2	1	2	1, 2	12, 15
B. Shutdown	2	1	2	3*,4* and 5*	16
21. Automatic Trip Logic					
A. Startup and Power Operation	2	1	2	1, 2	12
B. Shutdown	2	1	2	3*,4* and 5*	16
22. Reactor Trip System Interlocks					
A. Intermediate Range Neutron Flux, P-6	2	1	2	2, and*	8a
B. Power Range Neutron Flux, P-7	4	2	3	1	8b

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
C. Power Range Neutron Flux, P-8	4	2	3	1	8c
D. Power Range Neutron Flux, P-10	4	2	3	1, 2	8d
E. Turbine Impulse Chamber Pressure, P-13	2	1	2	1	8b
F. Power Range Neutron Flux, P-9	4	2	3	1	8e
G. Reactor Trip, P-4	2	1	2	1, 2, and *	14

TABLE 3.3-1 (Continued)

TABLE NOTATION

*With the reactor trip system breakers in the closed position, the control rod drive system capable of rod withdrawal, and fuel in the reactor vessel.

**The channel(s) associated with the protective functions derived from the out of service Reactor Coolant Loop shall be placed in the tripped condition.

#The provisions of Specification 3.0.4 are not applicable.

##Source Range outputs may be disabled above the P-6 (Block of Source Range Reactor Trip) setpoint.

ACTION STATEMENTS

ACTION 1 - With the number of OPERABLE channels one less than required by the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in HOT STANDBY within the next 6 hours and/or open the reactor trip breakers.

ACTION 2 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours.

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.1.

c. The QUADRANT POWER TILT RATIO is monitored in accordance with Technical Specification 3.2.4.

TABLE 3.3-1 (Continued)

ACTION 3 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement and with the THERMAL POWER level:

a. Below the P-6 (Block of Source Range Reactor Trip) setpoint, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above the P-6 Setpoint.

b. Above the P-6 (Block of Source Range Reactor Trip) setpoint, but below 5% of RATED THERMAL POWER, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above 5% of RATED THERMAL POWER.

c. Above 5% of RATED THERMAL POWER, POWER OPERATION may continue.

d. Above 10% of RATED THERMAL POWER, the provisions of Specification 3.0.3 are not applicable.

ACTION 4 - With the number of OPERABLE channels one less than required by the Minimum Channels OPERABLE requirement and with the THERMAL POWER level:

a. Below the P-6 (Block of Source Range Reactor Trip) setpoint, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above the P-6 Setpoint.

b. Above the P-6 (Block of Source Range Reactor Trip) setpoint, operation may continue.

ACTION 5 - With the number of OPERABLE channels one less than required by the Minimum Channels OPERABLE requirement, verify compliance with the SHUTDOWN MARGIN requirements of Specification 3.1.1.1 or 3.1.1.2, as applicable, within 1 hour and at least once per 12 hours thereafter.

ACTION 6 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours.

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.1.

ACTION 7 - Deleted.

TABLE 3.3-1 (Continued)

ACTION 8 - With less than the Minimum Number of Channels OPERABLE, declare the interlock inoperable and verify that all affected channels of the functions listed below are OPERABLE or apply the appropriate ACTION statement(s) for those functions. Functions to be evaluated are:

a. Source Range Reactor Trip.

b. Reactor Trip

Low Reactor Coolant Loop Flow (2 loops)
Undervoltage
Underfrequency
Pressurizer Low Pressure
Pressurizer High Level

c. Reactor Trip

Low Reactor Coolant Loop Flow (1 loop)

d. Reactor Trip

Intermediate Range
Low Power Range
Source Range

e. Reactor Trip
Turbine Trip

ACTION 9 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours.

b. For the affected protection set, the Trip Time Delay for one affected steam generator (T_S) is adjusted to match the Trip Time Delay for multiple affected steam generators (T_M) within 4 hours.

c. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.1.

TABLE 3.3-1 (Continued)

ACTION 10 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided that within 6 hours, for the affected protection set, the Trip Time Delays (T_S and T_M) threshold power level for zero seconds time delay is adjusted to 0% RTP.

ACTION 11 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided that within 6 hours, for the affected protection set, the Steam Generator Water Level - Low-Low (EAM) channels trip setpoint is adjusted to the same value as Steam Generator Water Level - Low-Low (Adverse).

ACTION 12 - With the number of OPERABLE channels one less than required by 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 4.3.1.1.1 provided the other channel is OPERABLE.

ACTION 13 - With the number of OPERABLE channels one less than the Total Number of Channels and with the THERMAL POWER level above the P-7 (enable reactor trips) setpoint place the inoperable channel in the tripped condition within 6 hours, operation may continue until performance of the next required CHANNEL FUNCTIONAL TEST.

ACTION 14 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within 6 hours.

ACTION 15 - With one of the diverse trip features (undervoltage or shunt trip attachment) inoperable, restore it to operable status within 48 hours or declare the breaker inoperable and apply ACTION 12. The breaker shall not be bypassed while one of the diverse trip features is inoperable except for up to 4 hours for performing maintenance to restore the breaker to OPERABLE status.

ACTION 16 - 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.

TABLE 3.3-2

REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
1. Manual Reactor Trip	Not Applicable
2. Power Range, Neutron Flux	$\leq$ 0.5 seconds*
3. Power Range, Neutron Flux, High Positive Rate	Not Applicable
4. Power Range, Neutron Flux, High Negative Rate	$\leq$ 0.5 seconds*
5. Intermediate Range, Neutron Flux	Not Applicable
6. Source Range, Neutron Flux	Not Applicable
7. Overtemperature ΔT	$\leq$ 8.0 seconds*
8. Overpower ΔT	$\leq$ 8.0 seconds
9. Pressurizer Pressure--Low	$\leq$ 2.0 seconds
10. Pressurizer Pressure--High	$\leq$ 2.0 seconds
11. Pressurizer Water Level--High	Not Applicable
12. Loss of Flow - Single Loop (Above P-8)	$\leq$ 1.0 second

*Neutron detectors are exempt from response time testing. Response time of the neutron flux signal portion of the channel shall be measured from detector output or input of first electronic component in channel.

TABLE 3.3-2 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
13. Loss of Flow - Two Loops (Above P-7 and below P-8)	$\leq$ 1.0 second
14. Main Steam Generator Water Level--Low-Low	
A. RCS Loop ΔT ($P \leq 50\%$ RTP; $P > 50\%$ RTP)	$\leq$ 8.0 seconds(1)
B. Steam Generator Water Level--Low-Low (Adverse, EAM)	$\leq$ 2.0 seconds(1)
C. Containment Pressure (EAM)	$\leq$ 2.0 seconds(1)
15. Deleted	
16. Undervoltage-Reactor Coolant Pumps	$\leq$ 1.2 seconds
17. Underfrequency-Reactor Coolant Pumps	$\leq$ 0.6 seconds
18. Turbine Trip	
A. Low Fluid Oil Pressure	Not Applicable
B. Turbine Stop Valve	Not Applicable
19. Safety Injection Input from ESF	Not Applicable
20. Reactor Trip Breakers	Not Applicable
21. Automatic Trip Logic	Not Applicable
22. Reactor Trip System Interlocks	Not Applicable

(1) Does not include Trip Time Delays. Response times noted include the transmitters, Eagle-21 process protection cabinets, solid state protection cabinets and actuation devices. This reflects the response time necessary for THERMAL POWER in excess of 50% RTP.

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	S/U(1)and R(9)	1, 2, and *
2. Power Range, Neutron Flux	S	D(2), M(3) and Q(6)	Q	1, 2
3. Power Range, Neutron Flux, High Positive Rate	N.A.	R(6)	Q	1, 2
4. Power Range, Neutron Flux, High Negative Rate	N.A.	R(6)	Q	1, 2
5. Intermediate Range, Neutron Flux	S	R(6)	S/U(1)	1, 2, and *
6. Source Range, Neutron Flux	S(7)	R(6)	M and S/U(1)	2, 3, 4, 5, and *
7. Overtemperature ΔT	S	R	Q	1, 2
8. Overpower ΔT	S	R	Q	1, 2
9. Pressurizer Pressure--Low	S	R	Q	1, 2
10. Pressurizer Pressure--High	S	R	Q	1, 2
11. Pressurizer Water Level--High	S	R	Q	1, 2
12. Loss of Flow - Single Loop	S	R	Q	1
13. Loss of Flow - Two Loops	S	R	N.A.	1
14. Steam Generator Water Level--Low-Low				
A. Steam Generator Water Level--Low-Low (Adverse)	S	R	Q	1, 2
B. Steam Generator Water Level--Low-Low (EAM)	S	R	Q	1, 2
C. RCS Loop ΔT	S	R	Q	1, 2
D. Containment Pressure (EAM)	S	R	Q	1, 2

TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
15. Deleted				
16. Undervoltage - Reactor Coolant Pumps	N.A.	R	Q	1
17. Underfrequency - Reactor Coolant Pumps	N.A.	R	Q	1
18. Turbine Trip				
A. Low Fluid Oil Pressure	N.A.	N.A.	S/U(1)	1
B. Turbine Stop Valve Closure	N.A.	N.A.	S/U(1)	1
19. Safety Injection Input from ESF	N.A.	N.A.	R	1, 2
20. Reactor Trip Breaker	N.A.	N.A.	M(5) and S/U(1)	1, 2, and *
21. Automatic Trip Logic	N.A.	N.A.	M(5)	1, 2, and *
22. Reactor Trip System Interlocks				
A. Intermediate Range Neutron Flux, P-6	N.A	R	N.A.	2, and *
B. Power Range Neutron Flux, P-7	N.A.	N.A.	N.A.	1
C. Power Range Neutron Flux, P-8	N.A.	R	N.A.	1
D. Power Range Neutron Flux, P-10	N.A.	R	N.A.	1, 2
E. Turbine Impulse Chamber Pressure, P-13	N.A.	R	N.A.	1
F. Power Range Neutron Flux, P-9	N.A.	R	N.A.	1
G. Reactor Trip, P-4	N.A.	N.A.	R	1, 2, and *
23. Reactor Trip Bypass Breaker	N.A.	N.A.	M(10)R(11)	1, 2, and *

Table4.3-1 (Continued)

NOTATION

* - With the reactor trip system breakers closed and the control rod drive system capable of rod withdrawal.

(1) - If not performed in previous 31 days.

(2) - Heat balance only, above 15% of RATED THERMAL POWER. Adjust channel if absolute difference greater than 2 percent.

(3) - Compare incore to excore AXIAL FLUX DIFFERENCE above 15% of RATED THERMAL POWER. Recalibrate if the absolute difference greater than or equal to 3 percent.

(4) - Deleted.

(5) - Each train or logic channel shall be tested at least every 62 days on a STAGGERED TEST BASIS. The test shall independently verify the OPERABILITY of the undervoltage and automatic shunt trip circuits.

(6) - Neutron detectors may be excluded from CHANNEL CALIBRATION.

(7) - Below P-6 (Block of Source Range Reactor Trip) setpoint.

(8) - Deleted.

(9) - The CHANNEL FUNCTIONAL TEST shall independently verify the operability of the undervoltage and shunt trip circuits for the manual reactor trip function.

(10) - Local manual shunt trip prior to placing breaker in service. Each train shall be tested at least every 62 days on a STAGGERED TEST BASIS.

(11) - Automatic and manual undervoltage trip.

3/4.3.2 ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2 The Engineered Safety Feature Actuation System (ESFAS) instrumentation channels and interlocks shown in Table 3.3-3 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3-4 and with RESPONSE TIMES as shown in Table 3.3-5.

APPLICABILITY: As shown in Table 3.3-3.

ACTION:

a. With an ESFAS instrumentation channel or interlock trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3-4, declare the channel inoperable and apply the applicable ACTION requirement of Table 3.3-3 until the channel is restored to OPERABLE status with the trip setpoint adjusted consistent with the Trip Setpoint value.

b. With an ESFAS instrumentation channel or interlock inoperable, take the ACTION shown in Table 3.3-3.

SURVEILLANCE REQUIREMENTS

4.3.2.1.1 Each ESFAS instrumentation channel and interlock shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations for the MODES and at the frequencies shown in Table 4.3-2.

4.3.2.1.2 The logic for the interlocks shall be demonstrated OPERABLE during the automatic actuation logic test. The total interlock function shall be demonstrated OPERABLE at least once per 18 months during CHANNEL CALIBRATION testing of each channel affected by interlock operation.

4.3.2.1.3 The ENGINEERED SAFETY FEATURES RESPONSE TIME of each ESFAS function shall be demonstrated to be within the limit at least once per 18 months. Each test shall include at least one logic train such that both logic trains are tested at least once per 36 months and one channel per function such that all channels are tested at least once per N times 18 months where N is the total number of redundant channels in a specific ESFAS function as shown in the "Total No. of Channels" Column of Table 3.3-3.

TABLE 3.3-3

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. SAFETY INJECTION, TURBINE TRIP AND FEEDWATER ISOLATION					
a. Manual Initiation	2	1	2	1, 2, 3, 4	20
b. Automatic Actuation Logic	2	1	2	1, 2, 3, 4	15
c. Containment Pressure-High	3	2	2	1, 2, 3	17*
d. Pressurizer Pressure - Low	3	2	2	1, 2, 3#	17*
e. Deleted					

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
f. Steam Line Pressure-Low	3/steam line	2/steam line in any steam line	2/steam line	1, 2, 3##	17*
2. CONTAINMENT SPRAY					
a. Manual	2	1**	2	1, 2, 3, 4	20
b. Automatic Actuation Logic	2	1	2	1, 2, 3, 4	15
c. Containment Pressure--High-High	4	2	3	1, 2, 3	18
3. CONTAINMENT ISOLATION					
a. Phase "A" Isolation					
1) Manual	2	1	2	1, 2, 3, 4	20
2) From Safety Injection Automatic Actuation Logic	2	1	2	1, 2, 3, 4	15

**Two switches must be operated simultaneously for actuation.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
3. CONTAINMENT ISOLATION					
b. Phase "B" Isolation					
1) Manual	2	1**	2	1, 2, 3, 4	20
2) Automatic Actuation Logic	2	1	2	1, 2, 3, 4	15
3) Containment Pressure-High-High	4	2	3	1, 2, 3	18
c. Containment Ventilation Isolation					
1) Manual	2	1	2	1, 2, 3, 4	19
2) Automatic Isolation Logic	2	1	2	1, 2, 3, 4	15
3) Containment Gas Monitor Radioactivity-High	2	1	1	1, 2, 3, 4	19
4) Containment Purge Air Exhaust Monitor Radioactivity-High	2	1	1	1, 2, 3, 4	19
5) Containment Particulate Activity High	2	1	1	1, 2, 3, 4	19

**Two switches must be operated simultaneously for actuation.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
4. STEAM LINE ISOLATION					
a. Manual	1/steam line	1/steam line	1/operating steam line	1, 2, 3	25
b. Automatic Actuation Logic	2	1	2	1, 2, 3	23
c. Containment Pressure--High-High	4	2	3	1, 2, 3	18
d. Steam Line Pressure-Low	3/steam line	2/steam line in any steam line	2/steam line	1, 2, 3#	17*
e. Negative Steam Line Pressure Rate-High	3/steam line	2/steam line in any steam lines	2/steam line	3##	17*

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
5. TURBINE TRIP & FEEDWATER ISOLATION					
a. Steam Generator Water Level--High-High	3/loop	2/loop in any operating loop	2/loop in each operating loop	1, 2, 3	17*
b. Automatic Actuation Logic	2	1	2	1, 2, 3	23
6. AUXILIARY FEEDWATER					
a. Manual Initiation	2	1	2	1, 2, 3	24
b. Automatic Actuation Logic	2	1	2	1, 2, 3	23
c. Main Steam Generator Water Level--Low-Low					
i. Start Motor-Driven Pumps					
a. Steam Gen. Water Level--Low-Low (Adverse)	3/Stm. Gen.	2/Stm. Gen. in any operating Stm. Gen.	2/Stm. Gen. in each operating Stm. Gen.	1, 2, 3	36*
b. Steam Gen. Water Level--Low-Low (EAM)	3/Stm. Gen.	2/Stm. Gen. in any operating Stm. Gen.	2/Stm. Gen. in each operating Stm. Gen.	1, 2, 3	36*
c. RCS Loop ΔT	4(1/loop)	2	3	1, 2, 3	37*

*Two switches must be operated simultaneously for actuation.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
d. Containment Pressure (EAM)	4	2	3	1, 2, 3	38*
ii. Start Turbine-Driven Pump					
a. Steam Gen. Water Level--Low-Low (Adverse)	3/Stm. Gen.	2/Stm. Gen. in any 2 operating Stm. Gen.	2/Stm. Gen. in each operating Stm. Gen.	1, 2, 3	36*
b. Stm. Gen. Water Level--Low-Low (EAM)	3/Stm. Gen.	2/Stm. Gen. in any 2 operating Stm. Gen.	2/Stm. Gen. in each operating Stm. Gen.	1, 2, 3	36*
c. RCS Loop ΔT	4(1/loop)	2	3	1, 2, 3	37*
d. Containment Pressure (EAM)	4	2	3	1, 2, 3	38*
d. S.I. Start Motor-Driven Pumps and Turbine Driven Pump	See 1 above (all S.I. initiating functions and requirements)				

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
e. Station Blackout Start Motor-Driven Pump associated with the shutdown board and Turbine Driven Pump	2/shutdown board	1/shutdown board	2/shutdown board	1, 2, 3	20
f. Trip of Main Feedwater Pumps Start Motor-Driven Pumps and Turbine Driven Pump	1/pump	1/pump	1/pump	1, 2	20*
g. Auxiliary Feedwater Suction Pressure-Low	3/pump	2/pump	3/pump	1, 2, 3	21*
h. Auxiliary Feedwater Suction Transfer Time Delays					
1. Motor-Driven Pump	1/pump	1/pump	1/pump	1, 2, 3	21*
2. Turbine-Driven Pump	2/pump	1/pump	2/pump	1, 2, 3	21*

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
7. LOSS OF POWER					
a. 6.9 kv Shutdown Board --Loss of Voltage					
1. Start Diesel Generators	2/shutdown board	1 loss of voltage on any shutdown board	2/shutdown board	1, 2, 3, 4	20*
2. Load Shedding	2/shutdown board	1/shutdown board	2/shutdown board	1, 2, 3, 4	20*
b. 6.9 kv Shutdown Board Degraded Voltage					
1. Voltage Sensors	3/shutdown board	2/shutdown board	2/shutdown board	1, 2, 3, 4	20*
2. Diesel Generator Start and Load Shedding Timer	2/shutdown board	1/shutdown board	1/shutdown board	1, 2, 3, 4	20*
3. SI/Degraded Voltage Enable Timer	2/shutdown board	1/shutdown board	1/shutdown board	1, 2, 3, 4	20*

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
8. ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INTERLOCKS					
a. Pressurizer Pressure - P-11/Not P-11	3	2	2	1, 2, 3	22a
b. Deleted					
c. Steam Generator Level P-14	3/loop	2/loop any loop	3/loop	1, 2	22c
9. AUTOMATIC SWITCHOVER TO CONTAINMENT SUMP					
a. RWST Level - Low	4	2	3	1, 2, 3, 4	18
COINCIDENT WITH Containment Sump Level - High	4	2	3	1, 2, 3, 4	18
AND Safety Injection	(See 1 above for Safety Injection Requirements)				
b. Automatic Actuation Logic	2	1	2	1, 2, 3, 4	15

TABLE 3.3-3 (Continued)

TABLE NOTATION

#Trip function may be bypassed in this MODE below P-11 (Pressurizer Pressure Block of Safety Injection) setpoint.

##Trip function automatically blocked above P-11 and may be blocked below P-11 when Safety Injection on Steam Line Pressure-Low is not blocked.

###The channel(s) associated with the protective functions derived from the out of service Reactor Coolant Loop shall be placed in the tripped mode.

*The provisions of Specification 3.0.4 are not applicable.

ACTION STATEMENTS

ACTION 15 - With the number of OPERABLE Channels one less than the Total Number of Channels, be in HOT STANDBY within 12 hours and in COLD SHUTDOWN within the following 30 hours; however, one channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1.1 provided the other channel is OPERABLE.

ACTION 16 - Deleted.

ACTION 17 - With the number of OPERABLE Channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours.

b. The Minimum Channels OPERABLE requirements is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.2.1.1.

ACTION 18 - With the number of OPERABLE Channels one less than the Total Number of Channels, operation may proceed provided the inoperable channel is placed in the bypassed condition and the Minimum Channels OPERABLE requirement is met; one additional channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1.1.

ACTION 19 - With less than the Minimum Channels OPERABLE, operation may continue provided the containment ventilation isolation valves are maintained closed.

ACTION 20 - With the number of OPERABLE Channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

TABLE 3.3-3 (Continued)

ACTION 21 - With less than the Minimum Number of Channels OPERABLE, declare the associated auxiliary feedwater pump inoperable, and comply with the ACTION requirements of Specification 3.7.1.2.

ACTION 22 With less than the Minimum Number of Channels OPERABLE, declare the interlock inoperable and verify that all affected channels of the functions listed below are OPERABLE or apply the appropriate ACTION statement(s) for those functions. Functions to be evaluated are:

a. Safety Injection
   Pressurizer Pressure
   Steam Line Pressure
   Negative Steam Line Pressure Rate

b. Deleted

c. Turbine Trip
   Steam Generator Level High-High
   Feedwater Isolation
   Steam Generator Level High-High

ACTION 23 - With the number of OPERABLE channels one less than the Total Number of Channels, be in at least HOT STANDBY within 6 hours and in at least HOT SHUTDOWN within the following 6 hours; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.2.1.1.

ACTION 24 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

ACTION 25 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or declare the associated valve inoperable and take the ACTION required by Specification 3.7.1.5.

ACTION 36 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours.

b. For the affected protection set, the Trip Time Delay for one affected steam generator (T_S) is adjusted to match the Trip Time Delay for multiple affected steam generators (T_M) within 4 hours.

TABLE 3.3-3 (Continued)

c. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.1.

ACTION 37 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided that within 6 hours, for the affected protection set, the Trip Time Delays (T_S and T_M) threshold power level for zero seconds time delay is adjusted to 0% RTP.

ACTION 38 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided that within 6 hours, for the affected protection set, the Steam Generator Water Level - Low-Low (EAM) channels trip setpoint is adjusted to the same value as Steam Generator Water Level - Low-Low (Adverse).

TABLE 3.3-4

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. SAFETY INJECTION, TURBINE TRIP AND FEEDWATER ISOLATION		
a. Manual Initiation	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Containment Pressure--High	$\leq$1.54 psig	$\leq$1.6 psig
d. Pressurizer Pressure--Low	$\geq$1870 psig	$\geq$1864.8 psig
e. Deleted		
f. Steam Line Pressure--Low	$\geq$600 psig steam line pressure (Note 1)	$\geq$592.2 psig steam line pressure (Note 1)

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
2. CONTAINMENT SPRAY		
a. Manual Initiation	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Containment Pressure--High-High	$\leq$2.81 psig	$\leq$2.9 psig
3. CONTAINMENT ISOLATION		
a. Phase "A" Isolation		
1. Manual	Not Applicable	Not Applicable
2. From Safety Injection Automatic Actuation logic	Not Applicable	Not Applicable
b. Phase "B" Isolation		
1. Manual	Not Applicable	Not Applicable
2. Automatic Actuation Logic	Not Applicable	Not Applicable
3. Containment Pressure--High-High	$\leq$2.81 psig	$\leq$2.9 psig
c. Containment Ventilation Isolation		
1. Manual	Not Applicable	Not Applicable
2. Automatic Isolation Logic	Not Applicable	Not Applicable

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
3. Containment Gas Monitor Radioactivity-High	$\leq 8.5 \times 10^{-3}$ μCi/cc	$\leq 8.5 \times 10^{-3}$ μCi/cc
4. Containment Purge Air Exhaust Monitor Radioactivity-High	$\leq 8.5 \times 10^{-3}$ μCi/cc	$\leq 8.5 \times 10^{-3}$ μCi/cc
5. Containment Particulate Activity-High	$\leq 1.5 \times 10^{-5}$ μCi/cc	$\leq 1.5 \times 10^{-5}$ μCi/cc
4. STEAM LINE ISOLATION		
a. Manual	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Containment Pressure--High-High	≤2.81 psig	≤2.9 psig
d. Steam Line Pressure--Low	≥600 psig steam line pressure (Note 1)	≥592.2 psig steam line pressure (Note 1)
e. Negative Steam Line Pressure Rate--High	≤100.0 psi (Note 2)	≤107.8 psi (Note 2)
5. TURBINE TRIP AND FEEDWATER ISOLATION		
a. Steam Generator Water level--High-High	≤81% of narrow range instrument span each steam generator	≤81.7% of narrow range instrument span each steam generator
b. Automatic Actuation Logic	N.A.	N.A.

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
6. AUXILIARY FEEDWATER		
a. Manual	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Main Steam Generator Water Level--Low-Low		
i. RCS Loop ΔT Equivalent to Power $\leq$50% RTP	RCS Loop ΔT variable input $\leq$50% RTP	RCS Loop ΔT variable input $\leq$ trip setpoint +2.5% RTP
Coincident with Steam Generator Water Level--Low-Low (Adverse) and	$\geq$15.0% of narrow range instrument span	$\geq$14.4% of narrow range instrument span
Containment Pressure-EAM	$\leq$0.5 psig	$\leq$0.6 psig
or		
Steam Generator Water Level--Low-Low (EAM)	$\geq$10.7% of narrow range instrument span	$\geq$10.1% of narrow instrument span
with		
A time delay (T_S) if one Steam Generator is affected	$\leq T_S$ (Note 5, Table 2.2-1)	$\leq$ (1.01) T_S (Note 5, Table 2.2-1)
or		
A time delay (T_m) if two or more Steam Generators are affected	$\leq T_m$ (Note 5, Table 2.2-1)	$\leq$ (1.01) T_m (Note 5, Table 2.2-1)

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
ii. RCS Loop ΔT Equivalent to Power > 50% RTP		
Coincident with Steam Generator Water Level--Low-Low (Adverse)	≥15.0% of narrow range instrument span	≥14.4% of narrow range instrument span
and		
Containment Pressure (EAM)	≤0.5 psig	≤0.6 psig
or		
Steam Generator Water Level--Low-Low (EAM)	≥10.7% of narrow range instrument span	≥10.1% of narrow range instrument span
d. S.I.	See 1 above (all SI Setpoints)	
e. Station Blackout	0 volts with a 5.0 second time delay	0 volts with a 5.0 ± 1.0 second time delay
f. Trip of Main Feedwater Pumps	N.A.	N.A.
g. Auxiliary Feedwater Suction Pressure-Low	≥ 2 psig (motor driven pump) ≥ 13.9 psig (turbine driven pump)	≥ 1 psig (motor driven pump) ≥ 12 psig (pump turbine driven)
h. Auxiliary Feedwater Suction Transfer Time Delays	4 seconds (motor driven pump)	4 seconds ±0.4 seconds (motor driven pump)
	5.5 seconds (turbine driven pump)	5.5 seconds ±0.55 seconds (turbine driven pump)

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
7. LOSS OF POWER		
a. 6.9 kv Shutdown Board Undervoltage Loss of Voltage		
1. Start of Diesel Generators		
a. Nominal Voltage Setpoint	4860 volts	4860 volts ±97.2 volts
b. Relay Response Time for Loss of Voltage	0 volts with a 1.5 second time delay	0 volts with a 1.5 ±0.5 second time delay
2. Load Shedding		
a. Nominal Voltage Setpoint	4860 volts	4860 volts ±97.2 volts
b. Relay Response Time for Loss of Voltage	0 volts with a 5.0 second time delay	0 volts with a 5.0 ±1.0 second time delay
b. 6.9 kv Shutdown Board-Degraded Voltage		
1. Voltage Sensors	6560 volts	6560 volts ± 33 volts
2. Diesel Generator Start and Load Shed Timer	300 seconds	300 seconds ± 30 seconds
3. SI/Degraded Voltage Logic Enable Timer	10 seconds	10 seconds ± 0.5 seconds
8. ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INTERLOCKS		
a. Pressurizer Pressure		
1. Not P-11, Automatic Unblock of Safety Injection on Increasing Pressure	≤1970 psig	≤1975.2 psig
2. P-11, Enable Manual Block of Safety Injection on Decreasing Pressure	≥1962 psig	≥1956.8 psig

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
8. ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INTERLOCKS (Continued)		
b. Deleted		
c. Deleted		
d. Steam Generator Level Turbine Trip, Feedwater Isolation P-14	(See 5. above)	
9. AUTOMATIC SWITCHOVER TO CONTAINMENT SUMP		
a. RWST Level - Low	130" from tank base	130" ± 2.71" from tank base
COINCIDENT WITH Containment Sump Level - High	30" above elev. 680'	30" ± 1.68" above elev. 680'
AND Safety Injection	(See 1 above for all Safety Injection Setpoints/Allowable Valves)	
b. Automatic Actuation Logic	N.A.	N.A.

Note 1: Time constants utilized in the lead-lag controller for Steam Pressure-Low are $\tau_1 \geq 50$ seconds and $\tau_2 \leq 5$ seconds.

Note 2: Time constant utilized in the rate-lag controller for Negative Steam Line Pressure Rate-High is $\tau_1 \geq 50$ seconds.

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
3. Pressurizer Pressure-Low	
a. Safety Injection (ECCS)	$\leq 32.0^{(1)}/28.0^{(7)}$
b. Reactor Trip (from SI)	≤ 3.0
c. Feedwater Isolation	$\leq 8.0^{(2)}$
d. Containment Isolation-Phase "A"(3)	$\leq 18.0^{(8)}$
e. Containment Ventilation Isolation	$\leq 5.5^{(8)(13)}$
f. Auxiliary Feedwater Pumps	$\leq 60^{(11)}$
g. Essential Raw Cooling Water System	$\leq 65.0^{(8)}/75.0^{(9)}$
h. Emergency Gas Treatment System	$\leq 28.0^{(8)}$
4. Deleted	
5. Negative Steam Line Pressure Rate-High	
a. Steam Line Isolation	≤ 8.0

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
6. Steam Line Pressure-Low	
a. Safety Injection (ECCS)	$\leq 28.0^{(7)}/28.0^{(1)}$
b. Reactor Trip (from SI)	≤ 3.0
c. Feedwater Isolation	$\leq 8.0^{(2)}$
d. Containment Isolation-Phase "A"(3)	$\leq 18.0^{(8)}/28.0^{(9)}$
e. Containment Ventilation Isolation	Not Applicable
f. Auxiliary Feedwater Pumps	$\leq 60^{(11)}$
g. Essential Raw Cooling Water System	$\leq 65.0^{(8)}/75.0^{(9)}$
h. Steam Line Isolation	≤ 8.0
i. Emergency Gas Treatment System	$\leq 38.0^{(9)}$
7. Containment Pressure--High-High	
a. Containment Spray	$\leq 208^{(9)}$
b. Containment Isolation-Phase "B"(12)	$\leq 65^{(8)}/75^{(9)}$
c. Steam Line Isolation	≤ 7.0
d. Containment Air Return Fan	≥ 540.0 and ≤ 660
8. Steam Generator Water Level--High-High	
a. Turbine Trip	≤ 2.5
b. Feedwater Isolation	$\leq 11.0^{(2)}$
9. Main Steam Generator Water Level - Low-Low	
a. Motor-driven Auxiliary Feedwater Pumps(4)	$\leq 60.0^{(14)}$
b. Turbine-driven Auxiliary Feedwater Pumps(5)(11)	$\leq 60.0^{(14)}$

TABLE 3.3-5 (Continued)

TABLE NOTATION

(10) The response time for loss of voltage is measured from the time voltage is lost until the time full voltage is restored by the diesel. The response time for degraded voltage is measured from the time the load shedding signal is generated, either from the degraded voltage or the SI enable timer, to the time full voltage is restored by the diesel. The response time of the timers is covered by the requirements on their setpoints.

(11) The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 for the turbine-driven Auxiliary Feedwater Pump.

(12) The following valves are exceptions to the response times shown in the table and will have the values listed in seconds for the initiating signals and the function indicated:

Valves: FCV-67-89, -90, -105, -106

Response times: 7.b, $75^{(8)}/85^{(9)}$

Valve: FCV-70-141
Response times: 7.b, $70^{(8)}/80^{(9)}$

(13) Containment purge valves only. Containment radiation monitor valves have a response time of 6.5 seconds or less.

(14) Does not include Trip Time Delays. Response times noted include the transmitters, Eagle-21 process protection cabinets, solid state protection cabinets, and actuation devices (up to and including pumps). This reflects the response times necessary for THERMAL POWER in excess of 50% RTP.

TABLE 4.3-2

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. SAFETY INJECTION AND FEEDWATER ISOLATION				
a. Manual Initiation	N.A.	N.A.	R	1, 2, 3, 4
b. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3, 4
c. Containment Pressure-High	S	R	Q	1, 2, 3
d. Pressurizer Pressure--Low	S	R	Q	1, 2, 3
e. Deleted				
f. Steam Line Pressure--Low	S	R	Q	1, 2, 3
2. CONTAINMENT SPRAY				
a. Manual Initiation	N.A.	N.A.	R	1, 2, 3, 4
b. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3, 4
c. Containment Pressure--High-High	S	R	Q	1, 2, 3

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
3. CONTAINMENT ISOLATION				
a. Phase "A" Isolation				
1) Manual	N.A.	N.A.	R	1, 2, 3, 4
2) From Safety Injection Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3, 4
b. Phase "B" Isolation				
1) Manual	N.A.	N.A.	R	1, 2, 3, 4
2) Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3, 4
3) Containment Pressure--High-High	S	R	Q	1, 2, 3
c. Containment Ventilation Isolation				
1) Manual	N.A.	N.A.	R	1, 2, 3, 4
2) Automatic Isolation Logic	N.A.	N.A.	M(1)	1, 2, 3, 4
3) Containment Gas Monitor Radioactivity-High	S	R	M	1, 2, 3, 4

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
4) Containment Purge Air Exhaust Monitor Radio-activity-High	S	R	M	1, 2, 3, 4
5) Containment Particulate Activity-High	S	R	M	1, 2, 3, 4
4. STEAM LINE ISOLATION				
a. Manual	N.A.	N.A.	R	1, 2, 3
b. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3
c. Containment Pressure--High-High	S	R	Q	1, 2, 3
d. Steam Line Pressure--Low	S	R	Q	1, 2, 3
e. Negative Steam Line Pressure Rate--High	S	R	Q	3
5. TURBINE TRIP AND FEEDWATER ISOLATION				
a. Steam Generator Water Level--High-High	S	R	Q	1, 2, 3
b. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3
6. AUXILIARY FEEDWATER				
a. Manual	N.A.	N.A.	R	1, 2, 3
b. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
c. Main Steam Generator Water Level--Low-Low				
1. Steam Generator Water Level--Low-Low (Adverse)	S	R	Q	1, 2, 3
2. Steam Generator Water Level--Low-Low (EAM)	S	R	Q	1, 2, 3
3. RCS Loop ΔT	S	R	Q	1, 2, 3
4. Containment Pressure (EAM)	S	R	Q	1, 2, 3
d. S.I.	See 1 above (all SI surveillance requirements)			
e. Station Blackout	N.A.	R	N.A.	1, 2, 3
f. Trip of Main Feedwater Pumps	N.A.	N.A.	R	1, 2
g. Auxiliary Feedwater Suction Pressure-Low	N.A.	R	M	1, 2, 3
h. Auxiliary Feedwater Suction Transfer Time Delays	N.A.	R	N.A.	1, 2, 3
7. LOSS OF POWER				
a. 6.9 kv Shutdown Board - Loss of Voltage				
1. Start Diesel Generators	S	R	M	1, 2, 3, 4
2. Load Shedding	S	R	N.A.	1, 2, 3, 4

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
b. 6.9 kv Shutdown Board - Degraded Voltage				
1. Voltage sensors	S	R	M	1, 2, 3, 4
2. Diesel Generators Start and Load Shedding Timer	N.A.	R	N.A.	1, 2, 3, 4
3. SI/Degraded Voltage Logic Timer	N.A.	R	N.A.	1, 2, 3, 4
8. ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INTERLOCKS				
a. Pressurizer Pressure, P-11/Not P-11	N.A.	R(2)	N.A.	1, 2, 3
b. Deleted				
c. Steam Generator Level, P-14	N.A.	R(2)	N.A.	1, 2
9. AUTOMATIC SWITCHOVER TO CONTAINMENT SUMP				
a. RSWT Level - Low COINCIDENT WITH	S	R	Q	1, 2, 3, 4
Containment Sump Level - High AND	S	R	Q	1, 2, 3, 4
Safety Injection	(See 1 above for all Safety Injection Surveillance Requirements)			
b. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3, 4

Intermediate and Source Range, Nuclear Flux (Continued)

Range Channels will initiate a reactor trip at approximately 25 percent of RATED THERMAL POWER unless manually blocked when P-10 becomes active. No credit was taken for operation of the trips associated with either the Intermediate or Source Range Channels in the accident analyses; however, their functional capability at the specified trip settings is required by this specification to enhance the overall reliability of the Reactor Protection System.

Overtemperature ΔT

The Overtemperature Delta T trip provides core protection to prevent DNB for all combinations of pressure, power, coolant temperature, and axial power distribution, provided that the transient is slow with respect to transit, thermowell, and RTD response time delays from the core to the temperature detectors (about 8 seconds), and pressure is within the range between the High and Low Pressure reactor trips. This setpoint includes corrections for axial power distribution, changes in density and heat capacity of water with temperature and dynamic compensation for transport, thermowell, and RTD response time delays from the core to the RTD output indication. With normal axial power distribution, this reactor trip limit is always below the core safety limit as shown in Figure 2.1-1. If axial peaks are greater than design, as indicated by the difference between top and bottom power range nuclear detectors, the reactor trip is automatically reduced according to the notations in Table 2.2-1.

Operation with a reactor coolant loop out of service below the 4 loop P-8 setpoint does not require reactor protection system setpoint modification because the P-8 setpoint and associated trip will prevent DNB during 3 loop operation exclusive of the Overtemperature Delta T setpoint.

Delta-T_0, as used in the Overtemperature and Overpower ΔT trips, represents the 100 percent RTP value as measured by the plant for each loop. This normalizes each loop's ΔT trips to the actual operating conditions existing at the time of measurement, thus forcing the trip to reflect the equivalent full power conditions as assumed in the accident analyses. These differences in RCS loop ΔT can be due to several factors, e.g., measured RCS loop flows greater than thermal design flow, and slightly asymmetric power distributions between quadrants. While RCS loop flows are not expected to change with cycle life, radial power redistribution between quadrants may occur, resulting in small changes in loop specific ΔT values. Accurate determination of the loop specific ΔT value should be made when performing Incore/Excore quarterly recalibration and under steady state conditions (i.e., power distributions not affected by xenon or other transient conditions.).

Overpower ΔT

The Overpower Delta T reactor trip provides assurance of fuel integrity, e.g., no melting, under all possible overpower conditions, limits the required range for Overtemperature Delta T protection, and provides a backup to the High Neutron Flux trip. The setpoint includes corrections for changes in density and heat capacity of water with temperature, and dynamic compensation for transport, thermowell, and RTD response time delays from the core to the RTD output indication.

The Overpower Delta T trip provides protection to mitigate the consequences of various size steam breaks as reported in WCAP-9226, "Reactor Core Response to Excessive Secondary Steam Releases."

Delta-T_0, as used in the Overtemperature and Overpower ΔT trips, represents the 100 percent RTP value as measured by the plant for each loop. This normalizes each loop's ΔT trips to the actual operating conditions existing at the time of measurement, thus forcing the trip to reflect the equivalent full power conditions as assumed in the accident analyses. These differences in RCS loop ΔT can be due to several factors, e.g., measured RCS loop flows greater than thermal design flow, and slightly asymmetric power distributions between quadrants. While RCS loop flows are not expected to change with cycle life, radial power redistribution between quadrants may occur, resulting in small changes in loop specific ΔT values. Accurate determination of the loop specific ΔT value should be made when performing Incore/Excore quarterly recalibration and under steady state conditions (i.e., power distributions not affected by xenon or other transient conditions.).

Pressurizer Pressure

The Pressurizer High and Low Pressure trips are provided to limit the pressure range in which reactor operation is permitted. The High Pressure trip is backed up by the pressurizer code safety valves for RCS overpressure protection, and is therefore set lower than the set pressure for these valves (2485 psig). The Low Pressure trip provides protection by tripping the reactor in the event of a loss of reactor coolant pressure.

Pressurizer Water Level

The Pressurizer High Water Level trip ensures protection against Reactor Coolant System overpressurization by limiting the water level to a volume sufficient to retain a steam bubble and prevent water relief through the pressurizer safety valves. No credit was taken for operation of this trip in the accident analyses; however, its functional capability at the specified trip setting is required by this specification to enhance the overall reliability of the Reactor Protection System.

Loss of Flow

The Loss of Flow trips provide core protection to prevent DNB in the event of a loss of one or more reactor coolant pumps.

Above 11 percent of RATED THERMAL POWER, an automatic reactor trip will occur if the flow in any two loops drops below 90 percent of nominal full loop flow. Above the P-8 interlock, automatic reactor trip will occur if the flow in any single loop drops below 90 percent of nominal full loop flow. This latter trip will prevent the minimum value of the DNBR from going below 1.30 during normal operational transients and anticipated transients when 3 loops are in operation and the Overtemperature Delta T trip setpoint is adjusted to the value specified for all loops in operation.

Steam Generator Water Level

The Steam Generator Water Level Low-Low trip protects the reactor from loss of heat sink in the event of a sustained steam/feedwater flow mismatch resulting from loss of normal feedwater or a feedwater system pipe break, inside or outside of containment. This function also provides input to the steam generator level control system. IEEE 279 requirements are satisfied by 2/3 logic for protection function actuation, thus allowing for a single failure of a channel and still performing the protection function. Control/protection interaction is addressed by the use of the Median Signal Selector which prevents a single failure of a channel providing input to the control system requiring protection function action. That is, a single failure of a channel providing input to the control system does not result in the control system initiating a condition requiring protection function action. The Median Signal Selector performs this by not selecting the channels indicating the highest or lowest steam generator levels as input to the control system.

With the transmitters located inside containment and thus possibly experiencing adverse environmental conditions (due to a feedline break), the Environmental Allowance Modifier (EAM) was devised. The EAM function (Containment Pressure (EAM) with a setpoint of $\leq$ 0.5 psig) senses the presence of adverse containment conditions (elevated pressure) and enables the Steam Generator Water Level - Low-Low trip setpoint (Adverse) which reflects the increased transmitter uncertainties due to this environment. The EAM allows the use of a lower Steam Generator Water Level - Low-Low (EAM) trip setpoint when these conditions are not present, thus allowing more margin to trip for normal operating conditions.

The Trip Time Delay (TTD) creates additional operational margin when the plant needs it most, during early escalation to power, by allowing the operator time to recover level when the primary side load is sufficiently small to allow such action. The TTD is based on continuous monitoring of primary side power through the use of RCS loop ΔT. Two time delays are calculated, based on the number of steam generators indicating less than the Low-Low Level trip setpoint and the primary side power level. The magnitude of the delays decreases with increasing

Steam Generator Water Level (Cont'd)

primary side power level, up to 50 percent RTP. Above 50 percent RTP there are no time delays for the Low-Low level trips.

In the event of failure of a Steam Generator Water Level channel, it is placed in the trip condition as input to the Solid State Protection System and does not affect either the EAM or TTD setpoint calculations for the remaining operable channels. It is then necessary for the operator to force the use of the shorter TTD time delay by adjustment of the single steam generator time delay calculation (T_S) to match the multiple steam generator time delay calculation (T_M) for the affected protection set, through the MMI. Failure of the Containment Pressure (EAM) channel to a protection set also does not affect the EAM setpoint calculations. This results in the requirement that the operator adjust the affected Steam Generator Water Level - Low-Low (EAM) trip setpoints to the same value as the Steam Generator Water Level - Low-Low (Adverse). Failure of the RCS loop ΔT channel input (failure of more than one T_H RTD or failure of a T_C RTD) does not affect the TTD calculation for a protection set. This results in the requirement that the operator adjust the threshold power level for zero seconds time delay from 50 percent RTP to 0 percent RTP, through the MMI.

Undervoltage and Underfrequency - Reactor Coolant Pump Busses

The Undervoltage and Underfrequency Reactor Coolant Pump bus trips provide reactor core protection against DNB as a result of loss of voltage or underfrequency to more than one reactor coolant pump. The specified setpoints assure a reactor trip signal is generated before the low flow trip setpoint is reached. Time delays are incorporated in the underfrequency and undervoltage trips to prevent spurious reactor trips from momentary electrical power transients. For undervoltage, the delay is set so that the time required for a signal to reach the reactor trip breakers following the simultaneous trip of two or more reactor coolant pump bus circuit breakers shall not exceed 1.2 seconds. For underfrequency, the delay is set so that the time required for a signal to reach the reactor trip breakers after the underfrequency trip setpoint is reached shall not exceed 0.6 seconds.

Turbine Trip

A Turbine Trip causes a direct reactor trip when operating above P-9. Each of the turbine trips provide turbine protection and reduce the severity of the ensuing transient. No credit was taken in the accident analyses for operation of these trips. Their functional capability at the specified trip settings is required to enhance the overall reliability of the Reactor Protection System.

Safety Injection Input from ESF

If a reactor trip has not already been generated by the reactor protective instrumentation, the ESF automatic actuation logic channels will initiate a reactor trip upon any signal which initiates a safety injection. This trip is provided to protect the core in the event of a LOCA. The ESF instrumentation channels which initiate a safety injection signal are shown in Table 3.3-3.

Reactor Trip System Interlocks

The Reactor Trip System Interlocks perform the following functions on increasing power:

P-6 Enables the manual block of the source range reactor trip (i.e., prevents premature block of source range trip).

P-7
P-13 Defeats the automatic block of reactor trip on: Low flow in more than one primary coolant loop, reactor coolant pump undervoltage and underfrequency, pressurizer low pressure, and pressurizer high level.

P-8 Defeats the automatic block of reactor trip on low RCS coolant flow in a single loop.

P-9 Defeats the automatic block of reactor trip on turbine trip.

P-10 Enables the manual block of reactor trip on power range (low setpoint), intermediate range, as a backup block for source range, and intermediate range rod stops (i.e., prevents premature block of the noted functions).

On decreasing power, the opposite function is performed at reset setpoints.

P-4 Reactor-tripped - Actuates turbine trip, closes main feedwater valves on T_{avg} below setpoint, prevents the opening of the main feedwater valves which were closed by a safety injection or high steam generator water level signal, allows manual block of the automatic reactuation of safety injection.

Reactor not tripped - defeats manual block preventing automatic reactuation of safety injection.

3/4.3.1 and 3/4.3.2 REACTOR TRIP AND ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

The OPERABILITY of the Reactor Trip and Engineered Safety Features Actuation Systems instrumentation and interlocks ensure that 1) the associated action and/or reactor trip will be initiated when the parameter monitored by each channel or combination thereof reaches its setpoint, 2) the specified coincidence logic is maintained, 3) sufficient redundancy is maintained to permit a channel to be out of service for testing or maintenance, and 4) sufficient system functional capability is available from diverse parameters.

The OPERABILITY of these systems is required to provide the overall reliability, redundancy and diversity assumed available in the facility design for the protection and mitigation of accident and transient conditions. The integrated operation of each of these systems is consistent with the assumptions used in the accident analyses. The surveillance requirements specified for these systems ensure that the overall system functional capability is maintained comparable to the original design standards. The periodic surveillance tests performed at the minimum frequencies are sufficient to demonstrate this capability.

The Engineered Safety Feature Actuation System interlocks perform the functions indicated below on increasing the required parameter, consistent with the setpoints listed in Table 3.3-4:

P-11 Defeats the manual block of safety injection actuation on low pressurizer pressure.

P-14 Trip of all feedwater pumps, turbine trip, closure of feedwater isolation valves and inhibits feedwater control valve modulation.

On decreasing the required parameter the opposite function is performed at reset setpoints.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

ENCLOSURE 2

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

SUPPPORTING AMENDMENT NO. 132 TO FACILITY OPERATING LICENSE NO. DPR-79

TENNESSEE VALLEY AUTHORITY

SEQUOYAH NUCLEAR POWER PLANT, UNIT 2

DOCKET NO. 50-328

1.0 INTRODUCTION

By letters dated January 24, April 25, May 15, and October 2, 1990, the Tennessee Valley Authority (TVA or the licensee) proposed to modify the Sequoyah Nuclear Plant (SQN), Units 1 and 2, Technical Specifications (TSs). The proposed changes are to revise the definition section; the Specifications 2.2.1, 3/4.3.1.1, and 3/4.3.2.1; and the associated bases for the specifications to reflect reactor protection system (RPS) upgrades and enhancements to be implemented during the respective Cycle 4 refueling outage in 1990 for each unit. Specifically, the following changes were proposed:

- Add a definition for a digital channel function test and an acronym for Rated Thermal Power.

- Revise the allowable values of Tables 2.2-1 and 3.3-4 to reflect rack drift allowances associated with the Eagle 21 digital process protection system.

- Revise the low-low steam generator water level entries of Tables 2.2-1, 3.3-1, 3.3-2, 3.3-3, 3.3-4, 3.3-5, 4.3-1, and 4.3-2 to reflect the incorporation of the environmental allowance modifier (EAM) and trip time delay (TTD) features.

- Delete the steam flow/feedwater flow mismatch and low steam generator water level reactor trip in Tables 2.2-1, 3.3-1, 3.3-2, and 4.3-1 to reflect the incorporation of a median signal selector (MSS) that separates the control and protection signals for steam generator water levels.

- Revise the overtemperature and overpower delta-T (differential temperature) entries of Tables 2.2-1 and 3.3-2 to reflect the elimination of the resistance temperature detector (RTD) bypass manifold of the reactor coolant system (RCS).

- Delete the high-differential pressure between steamline signals, revise the high-steam flow coincidence signal so that low steamline pressure alone initiates the corresponding engineered safety feature, and add a high negative steamline pressure rate actuation for steamline isolation in Tables 3.3-3, 3.3-4, 3.3-5 and 4.3-2 because a new steamline break (SLB) protection logic is implemented.

- Revise Actions Statements 2.b and 6.b of Table 3.3-1; Action Statements 15, 16, 17, 18, 21, and 23 of Table 3.3-3; and the channel functional test intervals of Table 4.3-2 to implement the Westinghouse Owners Group (WOG) Technical Specification Optimization Program (TOPS) engineered safety features actuation system enhancements of Westinghouse Electric Corporation WCAP-10271, Supplement 2.

- Delete outdated footnotes and unused action statements from the reactor protection table.

This is the licensee's TS Change Request 89-27. The letters dated April 25, May 15, and October 2, 1990, the second, third and fourth applications for TS 89-27, revise (1) setpoints and allowable values in the TS to properly reflect the setpoint methodology for Sequoyah and (2) the channel functional test interval for the improved rack drift term in the Eagle-21 system or to remove redundant and unnecessary information from the TSs. The fourth application revised the trip setpoints for the steam generator low-low water level trip which were submitted in the first and third applications. The revisions in the third application were to reflect the reference leg heatup environmental allowance associated with the TTD function. The revisions in the fourth application are to reflect the installation of modified Barton level transmitters at Unit 2 in the current Unit 2 Cycle 4 refueling outage. These transmitters were not installed at Unit 1 in the Unit 1 Cycle 4 refueling outage. The licensee stated that these transmitters will be installed at Unit 1 at a later date. These revisions are few in number compared to the proposed changes in the original application dated January 24, 1990 and do not alter the intent of the original application or the scope of the proposed action.

In supporting the proposed changes, the licensee provided clarifying information in several letters for the above TS applications. These letters and the applications listed above are given in Table 1. Also listed in Table 1 are a meeting and three audits conducted by the staff to evaluate these TS applications. The additional information provided by the clarifying letters, the second and third application letters, the meeting, and the NRC audits did not change the substance of the proposed action in the Federal Register Notice (55 FR 6119) published on February 21, 1990 for the proposed amendment and do not affect the staff's initial determination of no significant hazards consideration in that notice.

The summary for the meeting held on February 26, 1990 on the Eagle-21 process protection system was issued on March 22, 1990. The purpose of the meeting was to discuss the Eagle-21 System for Sequoyah as compared to the Eagle-21 equipment to be installed at Watts Bar. In particular, the differences in the Eagle-21 test, or Man-Machine Interface, carts for Sequoyah and Watts Bar were discussed.

2.0 EVALUATION

The staff's evaluation of the proposed changes in the TS applications dated January 24, April 25, and May 15, 1990 for RPS upgrades and enhancements will be discussed in the following sections: (1) Instrumentation and Control System Evaluation, (2) Reactor Systems Evaluation and (3) Containment System Evaluation. Each of these sections has its own list of references within the section. When needed, the staff will reference sections in the Sequoyah Final Safety Analysis Report (FSAR).

2.1 Instrumentation and Control System Evaluation

2.1.1 Introduction

The licensee requested changes to the TSs of Sequoyah Units 1 and 2. The proposed changes reflect modifications to the RPS both in the logic and the hardware designs. The major modifications include:

(1) Replace the existing Foxboro H-line analog process protection systems with a new Eagle-21 digital microprocessor-based process protection system and change the RPS and the engineering safety features actuatiom system (ESFAS) trip setpoints.

(2) Eliminate the RTD bypass loop measurement in the reactor coolant system.

(3) Modify the steamline break protection system.

(4) Implement the EAM within the RPS and the ESFAS.

(5) Implement the TTD within the RPS and the ESFAS.

(6) Implement the MSS System and eliminate the low feedwater flow reactor trip function.

The staff's evaluation and conclusion of these changes are presented in Section 2.1.5 of this report. The references are listed in Section 2.1.9.

2.1.2 Background

The Westinghouse Electric Corporation (Westinghouse) designed and manufactured a microprocessor-based Class IE system to replace the older analog protection and control process instrumentation system at Sequoyah. This new system has been designated as the Eagle-21 system and is being utilized for Sequoyah (SQN), Units 1 and 2. The Eagle-21 system has been implemented at the Watts Bar Nuclear Plant (WBN) in support of the elimination of the WBN reactor coolant system Resistance Temperature Detector (RTD) bypass manifold. The implementation of the Eagle-21 system at SQN is broader in scope than WBN's because all of the SQN analog process racks (13 total) are being replaced with digital equipment.

Improved electronic technology and accumulated operating plant experience have led to the development of a new design to replace the older analog system. Features of the Eagle-21 equipment include the following:

(1) Automatic surveillance testing capability.

(2) Self calibration (rack only) to reduce/eliminate rack drift and simplify calibration procedures.

(3) Self diagnostics capability to reduce troubleshooting time.

(4) Modular design to allow for a phased installation into existing process racks and use of existing field terminations.

(5) Hardware expansion capability to easily accommodate functional upgrade and plant improvements.

2.1.3 Eagle-21 Process Protection System Description

The Eagle-21 Process Protection System is a multiple microprocessor based digital protection system. It was designed to fit into the existing analog system racks at SQN. It will use the existing field terminal blocks and avoid new cable pulls or splices within the cabinets. The cabinet's internal cabling is prefabricated and labeled. The input signals include temperature, pressure, level, and flow measurement. The system also accepts analog voltage or current inputs from other nuclear process systems. The output signals provide (1) the partial trip signal to the solid state protection logic cabinets, annunciators, status lights, plant computer, and SPDS systems, and (2) analog output signals to indicators, recorders, and other monitoring systems. Although the generic Eagle-21 system has contact input modules, the licensee stated in its letter dated March 1, 1990 that the Sequoyah design does not use these modules.

The protection channel independence is maintained in the same way as the old system. Four independent channels are located in the separated process protection racks. A single failure of any one of these channels cannot affect the other channels. Surveillance testing utilizes the Man-Machine Interface (MMI) cart. The MMI cart is attached to the Eagle-21 via a cable plug into the front test panel of each Eagle rack. Tests will be performed on one rack at a time. Instructions entered into the MMI via the Touch Screen Menu will allow the testing to be performed automatically.

The Eagle-21 system has three major subsystems: An Input/Output Subsystem, a Loop Processor Subsystem, and a Tester Subsystem. These are discussed below:

I/O Subsystem

The input portion of the I/O subsystem consists of customized Analog Input systems of nuclear generating stations. These modules satisfy all of the signal conditioning, signal conversion, isolation, buffering, termination and testability requirements.

The signal conditioning modules are configurable to accept various process inputs including: 10-50 mA current loop (active or passive), 4-20 mA current loop (active or passive), 0-10 vdc, RTD's and field contacts. The Analog Input Module provides signals to the Loop Processor Subsystem. These modules also interface with the Tester Subsystem for test and diagnostic purposes.

The output portion of the I/O Subsystem consists of Analog Output, Contact Output, and Partial Trip Output modules. These modules receive data from the Loop Processor Subsystem and formulate analog, contact, and trip logic output signals. Class 1E isolation is provided for all analog and contact output signals.

Loop Process Subsystem

The Loop Processor Subsystem computes all of the algorithms and comparisons for the protective functions. The Loop Processor Subsystem consists of a Digital Filter Processor (DFP), Loop Calculation Processor (LCP), Communication Controller, Digital I/O Module, and a Digital to Analog (D/A) Converter.

The Digital Filter Processor receives analog signals from Analog Input Modules and performs both Analog to Digital (A/D) conversions and filtering operations on the input signals. The outputs of the Digital Filter Processor are then passed on to the Loop Calculation Processor. The Loop Calculation Processor performs calculations for protection channel functions, data comparison to setpoint values, and initiation of trip signals based on the data received from the Digital Filter Processor.

The Communication Controller collects information from the Loop Calculation Processor and transmits it to the Tester Subsystem.

The Digital I/O module is utilized to process contact inputs, contact outputs, and trip logic output signals.

The D/A Converter Module is utilized to convert digital values from the Loop Calculation Processor into analog values which are sent to analog output modules for further processing.

Tester Subsystem

The Tester Subsystem serves as the focal point of human interaction with the Eagle-21 system. It provides a user-friendly interface that permits test personnel to configure (i.e., adjust setpoints and tuning constants), test, and maintain the system. A Tester Subsystem consists of a Test Sequence Processor (TSP), Communication Controller, Digital to Analog (D/A) Converter Module, and a Digital I/O Module.

The Test Sequencer Processor reads information from the Communication Controller, Digital I/O Module, and the MMI test cart. This information allows the TSP to monitor the overall status of the Eagle-21 racks, perform self diagnostics, and initiate surveillance testing. The TSP provides information to the

Communication Controller, Digital I/O Module, D/A Converter, and MMI test cart. This information provides for status indiction and creation of the Signal Injection and Response (SIR) bus. This bus is distributed through the signal conditioning modules and allows the Tester Subsystem to control and test each module.

The Communication Controller receives information from the Loop Processor Subsystem Communication Controller. This information is then read by the TSP which allows it to monitor the status of the LCP. The Tester Subsystem Communication Controller also provides a serial link to the Test Panel, which allows for information display and printing when connected to the MMI Test Cart.

The D/A Converter Module receives digital information from the TSP and converts it into high resolution analog signals that are used for test injection via the SIR bus.

The Digital I/O Module receives digital information from the TSP and converts it into high resolution analog signals that are used for test injection via the SIR bus. The Digital I/O module receives information from the TSP and provides signals to a Contact Output Module that provides contacts for field devices.

2.1.4 Review Criteria

The Eagle-21 system is part of the reactor protection system which includes the reactor trip functions and the engineered safety features actuation functions. Therefore, the General Design Criteria (GDC) of Appendix A to 10 CFR 50, IEEE Standard 279, "Criteria for Protection Systems for Nuclear Power Generating Station" (10 CFR 50.55 a(h)), and the applicable acceptance criteria listed on Table 7-1 of the Standard Review Plan (NUREG-0800) will be used as the review guidance. In addition, the ANSI/IEEE standard ANS 7-4.3.2, 1982, "Application Criteria for Programmable Digital Computer Systems in Safety Systems of Nuclear Power Generating Stations" and R.G. 1.152, "Criteria for Programmable Digital Computer System Software in Safety Related Systems of Nuclear Power Plants," will be used to evaluate the Eagle-21 system software design verification and validation process.

2.1.5 Evaluation

2.1.5.1 Evaluation of Proposed Changes to the SQN Technical Specifications

The following four items have been reviewed and evaluated by the staff.

(1) A definition for a digital channel functional test is being added as Item c to Definition 1.6 for the channel functional test in the TSs, as follows:

A channel functional test shall be:

a. Analog channels - the injection of a simulated signal into the channel as close to the sensor as practicable to verify operability including alarm and/or trip functions.

b. Bistable channels - the injection of a simulated signal into the sensor to verify operability including alarm and/or trip functions.

c. Digital channels - the injection of a simulated signal into the channel as close to the sender input to the process racks as practicable to verify operability including alarm and/or trip functions.

Definitions 1.6.a and 1.6.b are in the TSs and Definition 1.6.c is proposed to be added to the TSs. The staff finds that the digital channel functional test definition is consistent with the existing channel functional test definitions in the TSs and is, therefore, acceptable.

(2) The allowable values of Tables 2.2-1 and 3.3-4 are being revised to reflect rack drift allowances associated with the Eagle-21 digital process protection system.

The staff has reviewed the Sequoyah instrument setpoint methodology document WCAP-11239 and 11626 (Reference 4), and finds that the allowable values of Tables 2.2-1 and 3.3-4 are consistent with the data in the setpoint methodology document which reflects the rack drift allowances associated with the Eagle-21 digital process protection system. These rack drift data are smaller than the existing analog rack drift data because the Eagle-21 system is more accurate than the Foxboro analog system. Therefore, the proposed allowable values are acceptable.

(3) Actions 17 and 18 of Table 3.3-3, and the channel functional test intervals of Table 4.3-2 are being revised to implement the Westinghouse Owners Group (WOG) Technical Specification Optimization Program (TOPS) engineered safety features actuation system enhancements of Westinghouse Electric Corporation WCAP-10271, Supplement 2. The actions are given below:

ACTION 17 - With the number of OPERABLE Channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within six hours.

b. The minimum Channels OPERABLE requirements is met; however, the inoperable channel may be bypassed for up to four hours for surveillance testing of other channels per Specification 4.3.2.1.1.

ACTION 18 - With the number of OPERABLE Channels one less than the Total Number of Channels, operation may proceed provided the inoperable channel is placed in the bypassed condition and the Minimum Channels OPERABLE requirement is met, one additional channel may be bypassed for up to four hours for surveillance testing per Specification 4.3.2.1.1.

The staff finds that the proposed action statements No. 17 and No. 18 and the channel functional test intervals of Table 4.3-2 for quarterly tests are consistent with the staff approved Topical Report WCAP-10271 and, therefore, are acceptable.

(4) The surveillance intervals in Table 4.3-2 are being revised to reflect the Eagle-21 system.

The proposed surveillance intervals and applicable modes are consistent with the existing values in the table for ESFAS instrumentation. Therefore, the proposed surveillance intervals and applicable modes are acceptable.

2.1.5.2 RTD Bypass Elimination

Mechanical Concerns

The mechanical modification removes the valves, piping snubbers, and supports associated with the RTD bypass system and replaces them with thermowell mounted fast response RTDs which are installed directly into the reactor coolant piping. Mechanical modifications begin with the removal of the existing bypass piping at each connection point to the reactor coolant system. The existing hot and cold leg penetrations are machined to accept RTD thermowells. On the hot leg, the scoop tip will be removed to allow the thermowell to protrude directly into the flow stream. The thermowell is installed inside the modified scoop and the RTD is installed within the thermowell. The crossover leg connection is capped and an additional cold leg boss, thermowell and RTD are added as an installed spare. The mechanical modification eliminates the need for periodic maintenance of the RTD bypass manifold which will reduce the occupational radiation exposure. The staff finds this acceptable.

The Sequoyah Eagle-21 design uses three hot leg RTD's input to obtain a single hot leg temperature (TH_{AVG}). The system used to calculate is referred to as the Temperature Averaging System (TAS). The Temperature Averaging System (TAS) becomes part of the thermal overpower and overtemperature protection system (Delta T/T_{AVG}). TAS output (TH_{AVG}) replaces the hot leg temperature signal previously measured in the bypass manifold RTD. The TH_{AVG} signal is used in the calculation of the delta temperature (Delta T) and average temperature (T_{AVG}). The modular design of the Eagle-21 electronics allows for installation of the digital hardware into existing process racks. One rack per protection channel set is configured. Channel separation is maintained throughout the Eagle-21 design. The staff finds this acceptable.

2.1.5.3 New Steamline Break Protection

The primary functions of the new steamline break protection system are to: (1) isolate non-ruptured steamlines following a secondary high energy line rupture and (2) inject borated water into the reactor coolant system.

The existing SQN steamline break protection logic includes a safety injection actuation based on:

(1) Low steamline pressure coincident with high steamline flow.
(2) Low-low average coolant temperature coincident with high steamline flow.
(3) High steamline differential pressure.
(4) Low pressurizer pressure.
(5) High containment pressure.

and a steamline isolation actuation based on:

(1) Low steamline pressure coincident with high steamline flow.
(2) Low-Low average coolant temperature coincident with high steamline flow.
(3) High-High containment pressure.

The new steamline break protection system is currently in use as the standard system for later vintage Westinghouse plants.

The new steamline break protection logic will initiate a safety injection based on:

(1) Low Steamline Pressure (any steamline).
(2) Low Pressurizer Pressure.
(3) High Containment Pressure.

and a steamline isolation actuation based on:

(1) Low Steamline Pressure.
(2) High-High Containment Pressure.
(3) High Negative Steamline Pressure Rate.

The new steamline break protection system modifies both the process protection system and the reactor protection system voting logic. In the process protection system, the steamline flow channels will be deleted. The steamline pressure channel is modified to delete the steamline differential pressure comparator output. Two new comparators will be added to the steamline pressure channel. One comparator detects high negative steam pressure rate (rate-lag compensated). The rate-lag, lead-lag and comparator functions are included in the EAGLE-21 process protection cabinet and provide built-in test features to measure the lead/lag derivative, and comparator functions during periodic channel testing.

In the reactor protection system, the reactor protection logic will be modified to delete the safety injection on steamline differential pressure, and the steamline isolation plus safety injection upon high steamline flow coincident with low steamline pressure. The new steamline break protection system logic requires the addition of a safety injection and steamline isolation on 2-out-of-3 coincidence of low steamline pressure, and a steamline isolation signal on 2-out-of-3 coincidence of high negative steam pressure rate.

The staff has audited the licensee's post modification test procedures and the test results to verify that the new logic is properly integrated into the reactor protection system. No open concern was revealed during the audit.

2.1.5.4 Environmental Allowance Modifier (EAM)

A Westinghouse Owners Group (WOG) survey of Westinghouse operating plants found that, between 1980 and 1985, 38 percent of all unplanned reactor trips were attributable to problems with main feedwater systems. A closer examination revealed that 43 percent of all inadvertent plant trips were initiated by either the low-low steam generator water level or the low feedwater flow trip signals. A WOG Trip Reduction and Assessment Program (TRAP) was established to investigate methods and design modifications to reduce the frequency of these inadvertent trips occurring in Westinghouse plants and thereby increase plant availability and reduce challenges to reactor protection systems.

By letter dated December 15, 1986, from L. D. Butterfield to J. Lyons, the WOG submitted WCAP-11342, "Modification of the Steam Generator Low-Low Level Trip Setpoint to Reduce Feedwater Related Trips," to the NRC for review and approval. This WCAP, as part of the WOG TRAP, proposes a design modification which, when implemented on a plant specific basis, can reduce the inadvertent plant trips related to low steam generator level signals by an Environmental Allowance Modifier which distinguishes between normal and adverse containment environmental conditions and automatically selects a low or high setpoint for the low-low level trip chosen for the corresponding normal or adverse containment conditions based on the exclusion/inclusion of instrumentation uncertainties related to the harsh environmental conditions. By utilizing the two different setpoints, more operational flexibility (and reduced spurious trips) is provided during normal conditions, while adequate protection is still provided during accident/adverse conditions.

The staff's generic review of the EAM design revealed that it is conceptually acceptable and may be used as a basis for plant-specific applications (Reference 1).

However, in order for the staff to perform a detailed design review of the EAM design for conformance to regulatory requirements, plant-specific submittals had to include the following information:

(1) Plant-specific protection system logic diagrams accompanied by proposed revisions to Chapter 7 of the FSAR including compliance statements with the applicable, existing plant-specific safety criteria (GDC's, RG's, IEEE STD 279, etc.) covering the plant design modifications.

(2) Proposed changes to the plant-specific Technical Specifications with an accompanying Significant Hazards Evaluation covering the EAM installation. This shall include new setpoints and allowable values for the steam generator low-low level trip and the new containment pressure bistables as part of their operability/surveillance requirements for the EAM circuitry. Also a discussion of the applicability of the WCAP methodology should be provided including a determination of the pressure setpoint.

(3) Proposed changes to the plant-specific Technical Specifications with an accompanying Significant Hazards Evaluation covering any changes related to operation of containment systems, if required, to ensure acceptability of the EAM installation.

(4) Plant-specific changes to the operator procedures to cover the use of the EAM reset controls.

(5) Detailed electrical schematics covering the design modification.

(6) Plant-specific human factor analyses for any hardware modification to the control room.

(7) The EAM conceptual design provides for testing of the associated instrument channels in the bypass mode. Since the licensing basis for a typical Westinghouse plant provides for testing with the channel under test in the trip mode, a discussion of the acceptability for testing in bypass (reference to an applicable, approved WCAP such as WCAP-10271 is acceptable) should be provided.

The licensee has provided the above plant-specific information for staff review. Specifically, the setpoint methodology documents (Reference 4), the EAM implementation documents, and the supporting document for testing in bypass and the annotated copy of the FSAR included the logic diagrams. The staff also audited the design modification package, test procedures and test results at the SQN site. No open concern was revealed during the audit.

2.1.5.5 Steam Generator Low-Low Level Trip Time Delay

Low water level, in any steam generator, will trip the reactor and actuate the auxiliary feedwater system. These actions are intended to protect the core and to maintain an adequate heat sink for decay heat removal. The most critical need for such protective action would occur following a total loss of feedwater to all steam generators, or a major feedwater line rupture while the plant is operating at full power. Therefore, the low steam generator water level protection system logic and setpoints are determined according to the requirements of these postulated conditions.

The same protective functions would also occur under less limiting conditions, such as the termination of feedwater to only one steam generator during plant startup operations. Under these conditions, reactor protection system action may safely be delayed, and thereby provide time for remedial operator action and for the natural stabilization of water level transients. Restoration of the steam generator water level during such a programmed delay would avoid an unnecessary reactor trip, and reduce the frequency of challenges to the reactor protection system (specifically, the frequency of reactor trip demands caused by feedwater-related problems).

By letter dated December 15, 1986, from L. D. Butterfield to J. Lyons, the Westinghouse Owners Group (WOG) submitted WCAP-11325, "Steam Generator Low Water Level Protection System Modifications to Reduce Feedwater-Related Trips," to the NRC for generic review and approval. This WCAP report, as part of the WOG TRAP, proposed a design modification, when implemented on a plant-specific basis, which can reduce the inadvertent plant trips related to low steam generator level signals by adding a time delay to the steam generator low-low water level initiated reactor trip and auxiliary feedwater actuation. Through the use of adjustable timers in the protection system logic, this modification would allow added time for natural steam generator level stabilization or operator intervention to avoid an undesirable, inadvertent protection system actuation.

The staff's generic review of the TTD design and timer design revealed that they are conceptually acceptable and may be used as a basis for plant-specific applications (Reference 1). However, in order for the staff to perform a detailed design review of the time delay modifications for conformance to regulatory requirements, plant-specific submittals had to include the following information:

(1) Plant-specific protection system logic diagrams accompanied by proposed revisions to Chapter 7 of the FSAR including compliance statements with the applicable, plant-specific safety criteria (General Design Criteria, Regulatory Guides, IEEE STD 279, etc.) covering the design modification.

(2) Proposed changes to the plant-specific technical specifications with an accompanying Significant Hazards Evaluation, covering any new response time values for reactor trip and auxiliary feedwater actuation on a low-low steam generator water level signal, the adjustment for the time delays (e.g., setpoint and allowable value accounting for calibration accuracy, drift, etc) as part of the operability/surveillance requirements of the automatic actuation logic, and new setpoint and allowable values for the P-8 and/or other interlocks utilized.

(3) Detailed electrical schematics covering the design modification with a discussion of the proposed periodic testing to be performed on the modified hardware installed.

(4) Discussion of the environmental qualification of equipment (e.g., sensors, timers, etc.) related to the design modification.

(5) Discussion of the total instrumentation uncertainties (e.g., calibration, drift, etc.) for the plant-specific power interlocks utilized and their impact upon the selection of the corresponding time delays.

(6) Plant-specific changes to the operator procedures resulting from a delay of reactor trip and auxiliary feedwater initiation.

(7) Plant-specific human factors analyses for additional displays in the control room.

The licensee has provided the above plant-specific information for staff review. Specifically, the setpoint methodology documents (Reference 4), the TTD implementation documents, and the operator procedures resulting from a delay of reactor trip and auxiliary feedwater initiation. The staff also audited the design modification package, test procedures and test results at the Sequoyah site. No open concern was revealed during the audit.

TTD Implementation Limit

In the staff's SER (Reference 1) on Topical Report WCAP-11325, the staff concluded that the use of a time delay for reactor trip and auxiliary feedwater interaction on low-low steam generator level for power levels in excess of the P-8 permissive is not acceptable at this time. This conclusion is based on an examination of the advantages and disadvantages of these delays at high power from an overall risk standpoint. Most low-low steam generator level trips occur from low power. Of those that occur at high power, only a fraction of these could be reduced by a delay in the low-low steam generator level trip and auxiliary feedwater actuation. The fraction is relatively small (approximately 12%).

On the other hand, the staff was concerned that delaying the trip and auxiliary feedwater actuation would introduce a complication which could reduce the steam generator inventory for the unlikely case in which the auxiliary feedwater system may not be immediately available on demand and further operator action in necessary to restore auxiliary feedwater flow.

The Sequoyah TTD design allows trip time delay up to 50% of the reactor rated thermal power. The evaluation of the TTD implementation limit is addressed in Section 2.2.2 below.

2.1.5.6 Median Signal Selector (MSS)

Each steam generator at Sequoyah has three independent water level instrument channels which provide input to the reactor trip system (RTS) for a reactor trip on two-out-of-three low-low water levels. This low-low steam generator water level reactor trip function is designed to protect the reactor from the loss of heat sink in the event of a sustained steam/feedwater mismatch or a low feedwater flow resulting from a loss of normal feedwater.

In the existing Sequoyah protection system, one of the steam generator water level instrument channels also supplies an input to the feedwater control system (FWCS). The FWCS controls the feedwater regulating valve which in turn regulates the feedwater flow into the steam generator. As a result, a common instrument channel is used for both the RTS and the FWCS. IEEE Standard 279-1971 (10 CFR 50.55a(h)) Section 4.7 requires protection to prevent control and protection system interactions. To satisfy the IEEE Standard 279 requirements, the low feedwater flow trip function was added to initiate a reactor trip during a condition of steam and feedwater flow mismatch in coincidence with low steam generator water level. This trip provides a diverse trip function to the low-low steam generator water level trip. The primary purpose is to resolve the control and protection system interactions concern. The accident analysis does not include the steam/feedwater flow mismatch in mitigating the consequences of any analyzed accidents. No credit was taken for the steam/feedwater flow mismatch because it is more conservative to use than direct low-low water level trip function.

The MSS system was proposed by the licensee for the FWCS. Instead of using one of the three steam generator water level instrument channels for control function, all three channels will be input to the FWCS. The MSS system will select the median of the three input signals. By selecting the median signal, the control system which causes the control and protection interactions will not be affected by a failed protection channel. The MSS will prevent adverse interaction between the feedwater control system and the RTS.

By letter dated March 1, 1990, TVA submitted a Topical Report WCAP-12417, "Median Signal Selector for Foxboro Series Process Instrumentation, Application to Deletion of Low Feedwater Flow Reactor Trip" (Reference 2), to provide justification for the deletion of the steam flow/feedwater flow mismatch reactor trip function.

The Topical Report WCAP-12417 addresses the engineering issues relative to the use of a median signal selector system, the hardware configuration, the operating principal, the reliability of the system, the capability for testing and the adequacy of failure detection within the MSS system.

The staff was concerned that an undetectable failure in the MSS system may cause control and protection system interactions. To resolve this concern, the licensee stated that the MSS has been provided with the capability for on-line testing. The MSS can be tested concurrently with the protection instrument channels feeding the unit. These protection channels are tested on a quarterly basis. The components used in the MSS system are high quality components, and the licensee has committed to test the MSS system on a quarterly basis concurrently with the protection channels (Reference 3).

The staff has previously approved the similar MSS design for Beaver Valley Unit 2 (Docket No. 50-412). An amendment to the Beaver Valley license was issued on February 20, 1990.

Based on the review of the Topical Report WCAP-12417, and the discussion with the licensee during two meetings held on February 26 and March 13, 1990 respectively, the staff finds that the proposed MSS for the FWCS in conjunction with deletion of low feedwater flow reactor trip is acceptable. The staff audited the licensee's test procedures to verify that the MSS system testing was properly implemented. No open concern was revealed during the audit.

2.1.6 Evaluation of Eagle-21 Software Design Implementation

2.1.6.1 Software Design and V&V Process

The Westinghouse Eagle-21 system software design and its software verification and validation (V&V) process is based on the experience gained trom the South Texas Qualified Display Processing System (QDPS) design and the Watts Bar Eagle-21 System (RTD bypass elimination) design. The software has been designed to be modular in structure. The smallest software unit is the "Procedure." A typical Procedure may have 10 lines of coding or a few pages of coding. Each procedure has a design performance specification and verification test specification. Once the verification test has been completed, it will be treated as a qualified component that can be used by the main program for different applications. The main program simply determines the sequence for execution of these procedures.

All software follows the standards established for software design by the vendor, which include the following:

- High-level module logic is used.
- No interrupts are allowed.
- No reentrance is allowed.
- Code format conforms to standards for both high-level and assembly language routines.
- All programs are single task.

The design process of the Eagle-21 system involved three stages:

(1) Define a system design requirements.

(2) Decompose the system design requirements into hardware and software design specifications. The software design specifications are further decomposed into subsystem, module, and procedure (unit) specification.

(3) Construct the hardware and various software into a system, and perform the validation testing of the system.

The verification process involves two stages:

(1) Review the design documents, the computer coding and the testing documents.

(2) Perform the independent software testing that includes the structural testing and the functional testing.

The validation has three major phases:

(1) Top-down functional requirement testing.

(2) Prudency review of the design and its implementation.

(3) Specific Man-Machine Interface (MMI) testing

After the verification and validation process, the software is installed in the programmable read only memory (PROM). The software and documentation are kept under strict configuration management control.

2.1.6.2 Software Verification and Validation Audit Report

On April 18 through 20, 1990, the staff performed an Eagle-21 software verification and validation (V&V) audit at Westinghouse Process Control Division where the Eagle-21 system was designed and manufactured. The staff compared the Westinghouse V&V process with the American National Standard ANS-7-4.3.2-1982, "Application Criteria for Programmable Digital Computer System in Safety System of Nuclear Power Generating Stations" to determine the adequacy of the software V&V process of the Eagle-21 system.

(1) Organization: Westinghouse has a formal V&V group which maintains independence from the software design group. The first and second levels of supervisors are independent. Communications between the design group and the V&V group are documented in written reports. The technical qualifications of the V&V team are comparable to those of the design team. The staff finds that the organizational qualifications and independence are in conformance with the Standard ANS-7.2-4.3.2-1982, and, therefore, are acceptable.

(2) Design document verification: The Eagle-21 system has formal auditable documentation which includes the following categories:

a. System Design, Verification and Validation Plan.
b. Functional Requirements Documents
c. Functional Decomposition Documents
d. System Design Matrix
e. Validation Basis
f. Software Coding Standards
g. Software Design Specification
h. Software Configuration Requirements
i. Environmental and Seismic Qualification Reports
j. Noise, Fault, Surge Withstand, and RFI Test Reports
k. Reliability Study
l. Verification Problem Reports
m. Validation Problem Reports

The staff selected the New Steam Line Break Protection Program as a thread path to audit through the following documents:

a. The functional requirement document which defines the functions required by this program, the applicable criteria and standards, the reference drawings, the environmental requirements, the indicators, status lights, controls, alarms, interlocks, trips, time response, noise levels, controller transfer functions, setpoints, requirements for associated equipment, and the failure mode requirements.

b. The functional decomposition document which provides instruction for design validation. The top-level functional requirements are decomposed into detailed sub-requirements. For each sub-requirement, a test or series of tests are identified to ensure that the specific sub-requirement is satisfied. Performance of these tests will constitute validation of the system functional requirements. This document provides design traceability of requirements as they pertain to the Eagle-21 process protection system replacement equipment and channels in those racks.

c. The system design matrix document which provides design traceability from the top-level functional requirement documents through the supporting software design requirements, system design specification, module software design specifications and factory acceptance/validation test results for a "top-to-bottom" design documentation road map to demonstrate system design verification compliance.

The staff's audit of all the documents related to the new steam line break protection program did not reveal any inconsistency in the V&V Process. The documents are complete and accurate.

(3) Verification problem reporting: There are three basic types of verification problem reports. They are the following:

a. Generic Problem Reports contain multi-module related problems or problems with system design requirement documentation.

b. Module Level Problem Reports contain issues relating to entire source file.

c. Units Level Problem Reports apply only to a single unit of code.

When problem reports are prepared by the V&V Group and ready to be turned over to the design group, the V&V Librarian will issue a formal release letter to the design group librarian listing the file name of the reports and their location. The problem report will be kept in a common directory in the V&V storage area that cannot be altered without the assistance of the V&V librarian. The design group will copy the released report and make corrections in the program. When problem reports are ready to be returned to the V&V Group, the design librarian will formally release the reports to the V&V librarian using the standard release form. The problem reports for a particular project will be kept in a common computer directory in the design storage area. Only the design librarian will have READ and WRITE privileges to this directory. The V&V Group will verify and retest the corrected program and sign-off to CLEAR the problem report.

The staff audited the verification problem reporting process and random checked several problem reports, and found that the documentations are complete and thorough. The problem reporting process is acceptable.

(4) Validation Process: The validation process is to complement the verification process and to ensure that the final implemented system (hardware and software) completely satisfied the system functional requirements. The major phases of the Eagle-21 validation process includes:

- Functional requirements Abnormal-Mode testing
- Prudency review of the design and its implementation
- Specific Man-Machine Interface (MMI) testing

The validation documents include:

- Functional Decomposition Documents
- Design Document Decomposition Matrix
- Problem Reports

The validation process was performed by a team of individuals independent from the design team. They have performed 21 comprehensive tests and 47 hardware/software reviews. A total of 13 validation problem reports were generated. All validation problem reports were satisfactorily resolved. Out of these 13 problem reports, only one required software change. Based on the audit review of these validation problem reports, the staff concluded that there do not appear to be serious software errors in the Eagle-21 System.

At the time of the audit, the final V&V report was not completed. By letter dated May 8, 1990, the licensee provided the V&V final report. The final report presents the results of the V&V Program conducted on the Eagle-21 System for Sequoyah.

The software verification for the Eagle-21 System for Sequoyah was completed in April 1990 with the total number of software units involved being 1100. For these units, a total of 658 verification problem reports were generated. All verification problem reports generated were resolved. All changes to the software documentation were reviewed and/or tested to demonstrate successful resolution of the problems found.

The system validation program for the Eagle-21 System for Sequoyah was also completed in April 1990 including 21 comprehensive tests and 47 hardware/software reviews. The hardware/software reviews and validation tests have been satisfactorily completed. All validation problem reports generated were successfully resolved.

It was noted that none of the errors identified in the validation problem reports were errors that would be expected to be identified during the verification process. All problem reports generated during the validation process are in areas specific to validation.

Based on the staff's audit finding and the results of the final V&V Report, the staff concludes that the Eagle-21 functional upgrade implemented for Sequoyah Unit 1 is demonstrated to meet its functional and design requirements.

2.1.7 Site Inspection Report

On May 3 and 4, 1990, the staff performed a site inspection of the Eagle-21 system at the Sequoyah Plant, Unit 1. The system will be installed at Unit 2 during the current Unit 2 Cycle 4 refueling outage. The purpose of the inspection was to verify the following:

(1) The Eagle-21 system installation does not violate the existing channel separation/independent criteria.

(2) The control room modifications agree with the Eagle-21 system design requirements.

(3) The post modification tests have been properly performed.

(4) The operator and the instrument maintenance personnel have been properly trained.

2.1.7.1 Eagle-21 System Installation Verification

There are thirteen Foxboro H-line analog process protection racks which will be replaced by the Eagle-21 racks. The field sensors are connected to the existing cabinet-mounted terminal blocks. The field cables were not changed except in few instances which related to the new steamline break protection system, the new annunciator windows and the new input for the post accident monitoring system where new cable routing were required. The licensee stated that all the input/output points calibration will be completed before entering Mode 4 operation.

During the April 18, 1990 audit meeting, the staff was concerned that there was a mix of Class IE and non-class IE outputs from the partial trip output board. The staff requested clarification regarding the partial trip output board design and operation. By letter dated May 8, 1990, the licensee provided the following clarification. The Eagle-21 Process Protection System Upgrade partial trip output board provides the interface between the Loop Calculation Processor (LCP) and the existing trip logic system. Each partial trip output board provides up to four independent channels of logic output for driving relays in the trip logic system. Each of the partial trip output boards may have a mix of Class IE and non-class IE outputs connected to the board channels. With the exception of an indirect connection to a classic ground, the four output channels are completely independent. During the site inspection, the licensee further clarified that for those cabinets which contain wiring for one division of Class IE and non-divisional non-IE circuits, the entire nondivisional circuit (including external cabling) must be separated from all wiring and cabling of the opposite redundant division of Class IE circuits. Based on these clarifications, there is no open concern on this issue.

2.1.7.2 Control Room Alarm Modification

The Eagle-21 equipment racks are located in the instrument room which is two floors below the main control room. The operator's interface with the Eagle-21 system is to acknowledge the following annunciator windows and status lights in the control room:

(1) Protection channel trouble (one status light per channel)
(2) Channel set failure (one window)
(3) Protection channel in bypass (one window per channel)
(4) RTD failure (one window per channel)
(5) TTD timer start (one window per steam generator)
(6) Adverse containment environment (one window)

During the May 3, 1990 inspection, these annunciator windows had not been installed in the main control room for Unit 1. The system operating instructions (SOI) related to these annunciator windows had not been issued. However, the simulator has implemented these alarm messages and the operators have been trained with the Eagle-21 System implementation. The annunciator window modifications and the SOI will be completed before entering Mode 4 operation.

2.1.7.3 Post Modification Testing

The staff audited the post modification testing documents including the Eagle-21 hardware site acceptance test, channel functional tests, instrument calibration records, and the QA procedures tracking the Eagle-21 programmable Read Only Memory (E-PROM). It appears that the test records are well kept and easy to trace. Although the post modification tests to accept the system as operable have not been completed at the present time (i.e., May 3, 1990), the licensee has kept the resident inspector informed of the testing progress on a daily bases. These tests will be completed before entering Mode 4 operation.

The post modification tests are performed on an overlapping basis. No integrated tests are planned. Although no major problems have been revealed from each individual test, the interaction between the plant live process signal to the Eagle-21 system and output to the solid state protection system has not been demonstrated. Because the Sequoyah Eagle-21 system is a first-of-a-kind microprocessor based protection system, extra cautions during the plant startup period is warranted. Therefore, the staff requested that the licensee report all the Eagle-21 system hardware/software problems to NRR during the plant startup period. The surveillance test records of the Eagle-21 system should be available for staff audit. A summary report of the Eagle-21 system should be submitted to the NRR on a six-month basis during the next operating cycle.

2.1.7.4 Training

The staff conducted a two day inspection of the training of Sequoyah personnel on the Eagle-21 system as part of the Sequoyah Inspection 90-17 on Units 1 and 2. During the inspection, the staff determined the following: ten surveillance maintenance personnel and all of the six shifts of reactor operators have been trained. The surveillance/maintenance personnel were trained in a 5-week course by Westinghouse Electric Corporation which designed and built the Eagle-21 System. These personnel had hands-on training with an Eagle-21 rack and the MMI test cart used to troubleshoot the system and perform surveillances and calibrations of the system. In their training, these personnel used the first draft of the TVA procedures to perform the surveillance and calibrations of the system. All three shifts, covering a 24-hour day, will be staffed with these trained personnel.

The licensed operators on shift have been trained in classes on the Sequoyah simulator for the Eagle-21 system. The remaining licensed operators in staff positions were scheduled to be trained by May 11, 1990. This training also included the other modifications being completed in the Unit 1 and Unit 2 Cycle 4 refueling outage: UHI removal, BIT deactivation, RTD bypass manifold removal, ACI deletion, AMSAC addition, and the cold leg injection accumulator and RWST changes. The simulator now models both Sequoyah Units 1 and 2 because these modifications will be done at Unit 2 in the current Unit 2 Cycle 4 refueling outage.

The staff reviewed the course material for training the surveillance/maintenance personnel and the licensed operators and discussed the material with at least one individual taking the courses. The staff also visited the simulator, audited the records of software changes to the simulator to reflect the modifications being completed at Units 1 and 2 and discussed the changes to the simulator with an instructor. This training is considered to be acceptable for the use of the Eagle-21 System at Sequoyah.

Based on its review during Sequoyah Inspection 90-17, the staff concludes that the training of surveillance/maintenance and licensed operators is sufficient to allow Unit 2 to startup and operate with the Eagle-21 System.

2.1.8 Conclusion

Based on our review of information provided by the licensee; the meetings held with the licensee and Westinghouse representative on February 26, March 13 and 14, 1990; the software audit on April 18 through 20, 1990; and the site inspection on May 3 and 4, 1990; the staff finds that there is reasonable assurance that the Eagle-21 System conforms to the applicable regulations and guidelines. The scope of the review included the FSAR descriptive information, 10 CFR 50.59 submittal (Reference 5), and several Westinghouse Topical Reports submitted by the licensee. All submittals are listed in in Table 1. The staff met four times with the licensee and the NSSS vendor. These meetings, which are also listed in Table 1 provided a focus for exchanging information and answering staff questions. Based on the reviews noted above and the exchange of information at the four meetings, the staff has reached the following conclusions:

The Eagle-21 System adequately conforms to the guidance for periodic testing in RG 1.22, "Periodic Testing of Protection System Actuation Functions," and IEEE 338, as supplemented by RG 1.118, "Periodic Testing of Electric Power and Protection Systems." The bypassed and inoperable status indication adequately conforms to RG 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems." The Eagle-21 System adequately conforms to the guidance on the application of the single-failure criterion in IEEE 379, as supplemented by RG 1.53, "Application of the single-failure criterion to Nuclear Power Plant Systems." On the basis of its review, the staff concludes that the Eagle-21 System satisfies IEEE 279 with regard to system reliability and testability. Therefore, the staff finds that GDC 21 is satisfied. The Eagle-21 system adequately conforms to the guidance in IEEE 384 as supplemented by RG 1.75, "Physical Independence of Electric Systems" for protection system independence. On the basis of its review, the staff concludes that this system satisfies IEEE 279 with regard to independence of systems and hence satisfies GDC 22.

On the basis of its review of the interface between the Eagle-21 System and plant-operating control systems, the staff concludes that the system satisfies IEEE-279 with regard to control and protection system interaction. Therefore, the staff finds that GDC 24 is satisfied. On the basis of its review of the software design and its verification and validation, the staff concludes that the Eagle-21 system satisfies the requirements of ANSI/IEEE-ANS-7.4.3.2-1982, "Application Criteria for Programmable Digital Computer Systems in Safety Systems of Nuclear Power Generating Stations" and Regulatory Guide 1.152, "Criteria for Programmable Digital Computer System Software in Safety-Related Systems of Nuclear Power Plants".

The staff's conclusions noted above are based on the requirements of IEEE 279 with respect to the design of the safety-related portion of the Eagle-21 system. Therefore, we find that 10 CFR 50.55 a (h) is satisfied. In summary, we conclude that the Eagle-21 System meets all of the applicable guidelines and regulations and that its utilization as discussed previously is acceptable.

However, because this is the first Eagle-21 System in an operating plant, this acceptance is also based on the licensee's commitments (Reference 10) to: (1) report to NRC all Eagle-21 system hardware/software problems encountered during Unit 2 startup, (2) submit to NRC a periodic six-month summary report of the Eagle-21 System operation over the next operating cycle for Unit 2, and (3) submit any software configuration changes or modifications to the NRC for staff review and approval prior to implementation if it is not consistent with the original software design process (i.e., Revision 3 of the final V&V report). The staff may audit the surveillance test records of the Eagle-21 System for Sequoyah.

2.1.9 References

(1) Letter from A. Thadani (NRC) to R. Newton (WOG), "Acceptance for Referencing of Licensing Topical Reports WCAP-11325, "Steam Generator Low Water Level Protection System Modifications to Reduce Feedwater-Related Trips," and WCAP-11342, "Modification of the Steam Generator Low-Low Level Trip Setpoint to reduce Feedwater Related Trips," dated January 7, 1988.

(2) Letter from E.G. Wallace (TVA) to NRC, "Sequoyah Nuclear Plant - Median Signal Selector - Westinghouse Electric Corporation WCAPS-12417 and 12418," dated March 1, 1990.

(3) Letter from E.G. Wallace (TVA) to NRC, "Sequoyah Nuclear Plant (SQN) Median Signal Selector (MSS) Testing," dated April 11, 1990.

(4) Letter from E.G. Wallace (TVA) to NRC, "Sequoyah Nuclear Plant Eagle-21 Setpoint Methodology - WCAP-11239 and 11626," dated April 23, 1990.

(5) Letter from E. G. Wallace (TVA) to NRC, "Sequoyah Nuclear Plant Eagle-21 Unreviewed Safety Question (10 CFR 50.59)," dated April 11, 1990.

(6) Letter from E.G. Wallace (TVA) to NRC, "Sequoyah Nuclear Plant Eagle-21 Process Protection System Upgrade Summary Report," dated May 8, 1990.

(7) Letter from E.G. Wallace (TVA) to NRC, "Sequoyah Nuclear Plant Eagle-21 Equipment Qualification Reports," dated May 8, 1990.

(8) Letter from E.G. Wallace (TVA) to NRC, "Sequoyah Nuclear Plant Eagle-21 Upgrade to SQN Reactor Protection System (RPS) Additional Information," dated May 8, 1990.

(9) Letter from E.G. Wallace (TVA) to NRC, "Sequoyah Nuclear Plant Eagle-21 Verification and Validation - Final Report," dated May 8, 1990.

(10) Letter from E.G. Wallace (TVA) to NRC, "Sequoyah Nuclear Plant (SQN) - Eagle 21 Functional Upgrade Commitments," dated May 10, 1990.

2.2 Reactor Systems Evaluation

2.2.1 Introduction

The licensee originally requested changes to TS 2.2.1, 3/4.3.1.1 and 3/4.3.2.1 and the associated bases to reflect modifications to the RPS (Reference 1, see Section 2.2.2.8 below). Revisions to the proposed changes were submitted in letters dated April 25 and May 15, 1990. Additional information was submitted by letters as indicated in Reference 2. The proposed proposed changes are given in Section 1.0 above.

The purpose of the changes is to improve the RPS's reliability and the plant's availability, by replacing analog RPS racks with digital equipment. The EAM and TTD were developed to reduce unnecessary feedwater related reactor trips, likewise the steam flow/feedwater flow mismatch reactor trip is deleted by implementing the MSS. The RTD bypass elimination reduces radiation exposure, improves plant availability, and reduces the maintenance. The new SLB protection logic eliminates inadvertent ESF actuations. The WOG TOPS will reduce plant surveillance testing and the editorial changes are made for clarity.

The changes are based on the WCAP-11239, Revision 4, "Setpoint Methodology for Protection Systems." The EAM feature is based on WCAP-11342PA, "Modification of the Steam Generator Low-Low Level Trip Setpoint to Reduce Feedwater Related Trips" (Reference 3). The TTD modification is based on WCAP-11325PA Rev. 1, "Steam Generator Low Water Level Protection System Modifications to Reduce Feedwater Related Trips" (Reference 3). The MSS implementation and the justification for the deletion of the steam flow/feedwater flow mismatch reactor trip is discussed in WCAP-12417, "Median Signal Selector" (MSS) (Reference 4). The RTD bypass elimination is discussed in the setpoint methodology including the overpressure and overtemperature delta-T setpoints. The new SLB protection logic is based on reanalyses of the affected FSAR Chapters 6 and 15 transients to demonstrate the adequacy of the new SLB logic.

2.2.2 Evaluation

2.2.2.1 Trip Time Delay (TTD), Environmental Allowance Modifier (EAM)

The TTD is a system of programmed and predetermined delay times for the low-low level steam generator (SG) reactor trip and auxiliary feedwater delay times, based on the power level at the time of the low-low level trip and the number of steam generators affected. In the Sequoyah design, the trip delay times are determined from two equations as a function of power (below 50% of rated thermal power). One relationship is for time delays with one SG affected and the other when more than one SG is affected. There is no time delay for power levels above 50% of rated thermal power. Once the low-low level setpoint is reached, the TTD acts to delay reactor trip and auxiliary feedwater system actuation to allow time for operator corrective action or for natural water level stabilization. The time delay has been estimated using the methodology in WCAP-11325PA Rev. 1 using the criteria: (a) that no DNB will take place 95% of the time at the 95% confidence level and (b) that the reactor coolant and the main steam system pressure remain below 110% of the corresponding system design pressure. During trip time delay it has been estimated that overpressurization will not take place. After a reactor trip, the auxiliary feedwater supply is adequate to remove the decay heat. However, the staff's approval of WCAP-11325PA, Revision 1, (Reference 3) limited the WCAP's applicability to power levels not above the P-8 permissive. The Sequoyah P-8 permissive corresponds to 35% of plant thermal power. However, the staff objective in approving WCAP-11325PA was to limit spurious plant trips due to the low-low steam generator signal. The intent of the limitation was to include all power levels which were subject to feedwater level variation which could activate the low-low level signal. For Sequoyah this power level is 50%, because both units have a second feedwater pump activated between 40% to 50% power. The expression of the limitation in WCAP-11325PA in terms of the P-8 was convenient for the model plant (i.e., Callaway) in which the P-8 permissive was at the 50% thermal power level. Therefore, the staff finds that the 50% power limit for Sequoyah is justifiable, acceptable, and in agreement with the intent of WCAP-11325PA.

The EAM steam generator low-low level trip conceptual design is discussed in WCAP-11325PA. The EAM can be described as an automatic switch that raises the SG low-low level trip setpoint to increase the environmental error allowance in the setpoint whenever a harsh containment environment is indicated by detection of an elevated containment pressure. The EAM can reduce the frequency of unnecessary feedwater-related trips by increasing the difference between the nominal SG water level and the low-low SG level trip setpoint during normal operation.

2.2.2.1.1 The ATWS Mitigating System Activation Circuity (AMSAC)

The ATWS mitigating system actuation circuitry (AMSAC) is required by 10 CFR 50.62. The AMSAC design is not to interfere with the reactor protection functions. The AMSAC as described in Reference 5 provides an independent back-up to the existing protection systems which initiates a turbine trip and actuates auxiliary feedwater flow in the event of an anticipated transient without a reactor trip while the power level is above 40% of rated thermal power. As implemented in the Sequoyah units, the AMSAC will trip the turbine and initiate the auxiliary feedwater if (1) the water level in three of four SGs drops 5% below the SG low-low level reactor trip setpoint and (2) the power is greater than 40%. If the power is greater than 50%, the TTD/EAM system does not operate and, if the power is below 40%, the AMSAC does not operate.

In the 40-50% power range, if the level in more than two SGs drops below the AMSAC setpoint then both the AMSAC and the TTD will be actuated. However, because the AMSAC delay is shorter than the TTD delay, the turbine could be tripped and the auxiliary feedwater initiated before the TTD had a chance to trip the reactor; in addition, the Sequoyah units are equipped with the P-9 permissive and the turbine trip will not cause a reactor trip (unless another trip is initiated somewhere else in the RPS) thus a reactor trip will not take place until the TTD delay lapses. Thus, the staff concludes that the AMSAC does not interfere in TTD's function and vice versa.

2.2.2.1.2 Loss of Normal Feedwater

A plant specific loss of normal feedwater analysis (i.e., FSAR Section 15.2.8) was carried out to demonstrate that the auxiliary feedwater system is of sufficient capacity to remove core decay heat, stored energy and RCS pump heat following reactor trip. In this case, a reactor trip on SG low-low water level will occur. The analyses were carried out using the LOFTRAN code (Reference 6) for power levels below 50% of the rated thermal power. The results showed that the auxiliary feedwater capacity is adequate and that the RCS heatup is controlled. This analysis also confirms that the TTD does not invalidate the FSAR conclusions for the feedline break transient.

2.2.2.1.3 LOCA Accidents

Plant specific analyses showed that the LOCA related accidents are unaffected by the TTD and EAM modifications.

2.2.2.1.4 TTD and EAM Conclusions

In summary, the staff concludes that the proposed TTD/EAM modifications are acceptable because of the following: (1) within the 95% probability 95% confidence level that minimum departure from nucleate boiling ratio (MDNBR) will not be reached, (2) primary and secondary pressure will remain below 110% of their respective design limits, (3) the pressurizer will not fill, (4) there is no detrimental interaction with the AMSAC, (5) there is no impact on the FSAR conclusions for the feedline break analysis, and (6) there is no impact on the LOCA related accident analyses. Therefore, the staff concludes that the TTD/EAM modifications are acceptable.

2.2.2.2 RTD Bypass Elimination

The RTD bypass line is being replaced by three RTDs mounted in thermowells 120° apart in the same location in the hot leg of the reactor coolant system (RCS). Two RTDs will be placed in the cold leg at the reactor coolant pump (RCP) discharge. The elimination of the RTD bypass causes an increase in the response time of the temperature detectors from 6.0 sec to 8.0 sec which causes the overpower delta-T and overtemperature delta-T signals to be delayed by 2.0 seconds compared to the existing analyis. In addition, the RTDs generate delta-Ts and an average RCS temperature (T_{ave}) in each loop which are used in the following: low-T_{ave} feedwater isolation, low-low T_{ave} SI/steamline isolation, control rod control, steam dump control, pressurizer level control and RCS flow measurement. RCS flow and T_{ave} determination are the only parameters having a possible effect on the LOCA analysis. However, the uncertainties associated with the RTDs are within the current limits. Therefore, the RCS inlet/outlet temperature, the thermal design flow rate and the SG thermal-hydraulic data will not be affected, consequently the LOCA related accident analysis is not affected by the RTD modification.

The RTD bypass elimination was examined with respect to its impact on the non-LOCA safety analyses. The anticipated transients which could potentially be affected are the following:

- uncontrolled RCCA withdrawal at power (overtemperature delta-T or high neutron flux)
- uncontrolled boron dilution,
- excessive load increase,
- accidental RCS depressurization,
- overpower delta-T, and
- steamline break with the mass/energy release outside containment.

The results showed that either the delayed signal from the RTD modification is not used as a primary trip signal or whenever it is used the safety analysis criteria are met. Therefore, the staff concludes that the RTD modification is acceptable.

2.2.2.3 New Steamline Break Protection

As in the old steamline break protection, the new concept is also based on safety injection and steamline isolation. Safety injection will result from low steamline pressure, low pressurizer pressure, or high containment pressure. Steamline isolation will be actuated from high-high containment pressure, high negative steamline pressure rate, or low steamline pressure. The new steamline break protection was reviewed to ascertain that the new logic is acceptable and at least an equivalent level of protection is offered in the new logic as in the old logic.

The following non-LOCA transients have been analyzed:

- Uncontrolled rod cluster control assembly (RCCA), or control rod, withdrawal from a subcritical condition (FSAR-15.2.1),
- Uncontrolled RCCA withdrawal at power (FSAR-15.2.2),
- RCCA misalignment (FSAR-15.2.3),
- Uncontrolled boron dilution (FSAR-15.2.4),
- Partial and complete loss of forced reactor coolant flow (FSAR-15.2.5),
- Startup of an inactive reactor coolant loop (FSAR-15.2.6),
- Loss of external electrical load/turbine trip (FSAR-15.2.7),
- Loss of normal feedwater (FSAR-15.2.8),
- Loss of offsite power to the station auxiliaries (FSAR-15.2.9),
- Excessive heat removal due to feedwater system malfunctions, (FSAR-15.2.10),
- Excessive load increase (FSAR-15.2.11),
- Accidental depressurization of the RCS (FSAR-15.2.12),
- Rupture of a main steam line (FSAR-15.4.2.1),
- Spurious operation of a safety injection system at power (FSAR-15.2.14),
- Major rupture of a main feedwater pipe (FSAR-15.2.2),
- Rupture of a control rod drive mechanism housing (FSAR-15.4.6),

- Steamline break, coincident with rod withdrawal at power,
- Steamline break mass/energy release inside containment (FSAR-6.2)

The results of the analyses showed that one of the following was true for each of the above transients: (1) steamline isolation and safety injection were not required, (2) there is no impact from the Eagle-21 System, (3) the analyses criteria are met, or (4) there is no difference from the old analysis. The LOCA-related and steamline break analyses are unaffected by this modification. Therefore, the staff concludes that the proposed protection system modifications are acceptable with respect to the steamline break protection.

2.2.2.4 Elimination of the Low-Feedwater Flow Reactor Trip, Using the Median Signal Selector (MSS)

Elimination of the low feedwater flow reactor trip does not require any reanalysis of the non-LOCA safety analysis because this trip was never assumed to be a primary reactor protection trip. However, the same signal detectors and transmitters used in the low-feedwater flow trip provide the signals used for feedwater control, but the introduction of the MSS addresses all control and protection signals and insures that the MSS does not impact the non-LOCA transients.

The LOCA analyses on the other hand assume reactor trip and safety injection signals based on low pressurizer pressure or high containment pressure, therefore, the LOCA accident analyses are unaffected by this modification.

2.2.2.5 Steam Generator Tube Rupture (SGTR)

The Sequoyah FSAR Section 15.4.3 demonstrated that the radiological consequences of a SGTR are below the exposure guidelines in 10 CFR 100. The consequences of the Eagle-21 equipment and limit setting changes, including the RTD two second response time increase, are insignificant and the FSAR conclusions for the SGTR remain unchanged.

2.2.2.6 Conclusion

We have reviewed the TVA proposed Eagle-21 control and safety system implementation from the safety function point of view. Specifically, this safety evaluation addressed the RTD bypass elimination, the new steamline break protection, the median signal selector, the time trip delay, and the environmental allowance modifier. In addition, we examined the trip time delay with the ATWS mitigation actuation circuity. In all cases, we find that the proposed modifications did not exceed the design or existing regulatory limits, thus, the staff concludes that the proposed changes are acceptable.

2.2.2.7 Technical Specification Changes

The proposed technical specification changes reflect the modifications in the RPS, revise the definition sections, and revise the TS Bases of Specifications: 2.2.1, 3/4.3.1.1, and 3/4.3.2.1. Incorporation of the Eagle-21 digital process protection system modifications are expected to improve plant availability and reliability. In addition, the Westinghouse Owner's Group technical specification optimization program for engineered safety features actuation system is implemented. The specific changes and their evaluation follows:

(1) Tables 2.2-1, 3.3-1 to 3.3-5, 4.3-1 and 4.3-2 are revised to reflect the TTD and EAM on the low-low steam generator level trip signal.

The changes provide for the power range and the corresponding trip time delay calculation and accounts for the environmental allowance modifier based on low containment pressure. The conditions described in the technical specification changes reflect the description of the TTD and EAM functions that have been generically approved in Reference 4 and thus are acceptable.

(2) Tables 2.2-1. 3.3-1, 3.3-2 and 4.3-1 reflect the deletion of the steam/feedwater flow mismatch and the low-low SG water level reactor trip and the incorporation of the MSS.

The median signal selector was found acceptable in the accident analyses. The technical specification changes reflect the deletion of steam/feedwater flow mismatch and the low-low SG water level trip, and the implementation of the MSS. These changes are acceptable, because safety analyses considerations showed that they provide an equal level of protection as the previous sets of signals.

(3) Tables 2.2-1 and 3.3-2 are revised to reflect the RTD bypass elimination and its effect on the overtemperature delta-T and overpower delta-T.

There are several entries in Tables 2.2-1 and 3.3-2 which changed in the specifications associated with the RTD bypass elimination corresponding to time parameters in the estimation of the overtemperature delta-T and overpower delta-T. The transients affected due to the longer response time have been reanalyzed using the trip functions incorporated in the new expressions (in these technical specification changes) and found acceptable. Therefore, these specification changes are acceptable.

(4) Tables 2.3-3, 3.3-4, 3.3-5 and 4.3-2 are revised to incorporate the new steamline break protection logic which reflects deletion of (a) the high steamline differential pressure protection signal, (b) high steamline flow and (c) low-low average coolant temperature and the addition of (a) low steamline pressure, (b) low pressurizer pressure, (c) high containment pressure and, (d) high negative steamline pressure rate for actuation of safety injection and/or actuation of steamline isolation. Reanalyses with the new steamline break protection showed that it provides an equivalent level of protection (and reduced spurious actuations) and, thus, it is acceptable.

(5) In Table 3.3-1 actions 2.6 and 6.6, in Table 3.3-3 actions 15 to 18, 21 and 23 and the channel functional test intervals in Table 4.3-2 have been revised to implement the Westinghouse Owners Group technical specification optimization program engineered safety features actuation system enhancements (WCAP-10271PA, Supplement 2, Revision 1).

All of the above changes have been reviewed and approved in the topical report WCAP-10171PA except for Table 3.3-3 Action Statements 21 and 23 and Table 4.3-2 surveillance intervals. These action statements are not being changed by the proposed action and the surveillance intervals are addressed in Section 2.1.5.1 above. The other changes are acceptable because they have been generically approved.

2.2.2.8 References

(1) Letter from M.J. Ray, Tennessee Valley Authority to USNRC "Sequoyah Nuclear Plant (SQN) - Technical Specification (TS) Change 89-27," dated January 24, 1990.

(2) (a) Letter from E. G. Wallace, TVA, "Sequoyah Nuclear Plant (SQN) - Eagle-21 Unreviewed Safety Questions USQ," dated April 11, 1990.

(b) Letter from M. J. Ray TVA to USNRC, "Sequoyah Nuclear Plant Technical Specification Change 89-27," dated January 24, 1990.

(c) Letter from E. G. Wallace, TVA to USNRC, "Sequoyah Nuclear Plant Steam Generator Low Water Level Trip Time Delay, Additional Information," dated May 9, 1990.

(3) WCAP-11325PA, Rev. 1, "Steam Generator Low Water Level Protection System Modifications to Reduce Feedwater - Related Trips" by S. Miranda et al., February 1988.

(4) WCAP-12417, "Median Signal Selector for Foxboro Series Process Instrumentation, Application to Deletion of Low Feedwater Flow Reactor Trip" by J. F. Mermigus, dated October 1989.

(5) WCAP-10858PA, "AMSAC Generic Design Package" by M. R. Adler, dated June 1985.

(6) WCAP-7907-P-A, "LOFTRAN Code Description" by T. W. T. Burnett et al., Westinghouse Electric Corporation, dated April 1984.

2.3 Containment System Evaluation

TVA discussed the effect on containment integrity of the modifications to Sequoyah involved with the proposed TS changes. In its letter dated April 11, 1990, it stated that these modifications would not have an adverse impact on the mass and energy releases from the design basis Loss-of-Coolant Accident (LOCA) and Main Steam Line Break (MSLB). These accidents have been reanalyzed by TVA to include these modifications and other modifications which were planned for the Cycle 4 refueling outages for the units. These other modifications include upper head injection (UHI) removal, boron injection tank deactivation, and VANTAGE 5 Hybrid fuel use in the core. The reanalysis of the depressurization of the main steam system, main steam line rupture, small break LOCA and large break LOCA were submitted by TVA in its letter dated January 12, 1990 for the removal of the UHI during the current Cycle 4 refueling outage.

The reanalysis of the containment response to the large break LOCA was submitted by TVA in its letter dated January 12, 1990 for its TS Change Request 90-05, the extension of the ice weighing interval for the ice condenser to 18 months. The new peak containment pressure is 10.9 psi following the large break LOCA. This peak pressure is below the design value of 12 psi for the containment. The staff accepted (1) the reanalysis of the effect of the above accidents on the fuel in the core in its letter dated May 11, 1990 approving Amendment 140 in its letter dated March 2, 1990 approving Amendments 131 and 118 for Units 1 and 2, respectively. Therefore, the staff concludes that the modifications involved with the proposed TS changes for the RPS upgrades and enhancements do not adversely affect containment integrity.

2.4 Editorial Technical Specification Changes

The licensee has used the acronym "RTP" for Rated Thermal Power in its proposed changes. Rated Thermal Power is defined in Definition 1.25 in Section 1.0 of the TSs. The acronym "RTP" will be added to the words Rated Thermal Power in Definition 1.25. This change is acceptable.

Action statements in Tables 3.3-1, 3.3-3, and 4.3.1 are proposed to be deleted because they are not needed for these tables. The staff agrees that these action statements are not needed; therefore, the proposed changes are acceptable.

A note and astericks referring to the note for item "7" in Tables 3.3-3 and 3.3-4 are proposed to be deleted because the footnote is no longer needed for the table. The footnote refers to when a modification must be completed. Because the date is in the past, the footnote is not needed; therefore, the proposed change is acceptable.

2.5 Conclusion

Based on the above, the staff concludes that the proposed use of the Eagle-21 System, the EAM, the TTD, the MSS, the new steamline break protection logic, and the TOPS engineering safety features actuation system enhancements of WCAP-10271, Revision 2, are acceptable for Sequoyah Units 1 and 2. The staff also concludes that the proposed changes to the Sequoyah TSs to incorporate these upgrades and enhancements are acceptable.

These RPS upgrades and enhancements were implemented at Unit 1 during the Unit 1 Cycle 4 refueling outage. Therefore, the proposed TSs for Unit 1 were issued in the staff's letter dated May 16, 1990.

The TVA applications also proposed changes for the Unit 2 TSs. The RPS upgrades and enhancements associated with the proposed TS changes are being implemented at Unit 2 during the current Unit 2 Cycle 4 refueling outage. The TS changes for Unit 2 are being issued at this time.

In the letter dated May 10, 1990, the licensee committed to (1) report Eagle-21 System hardware, design software, and maintenance problems encountered during the startup of Unit 1 from the current Cycle 4 refueling outage; (2) submit, for Unit 1 operating Cycle 5, six-month reports discussing the operation of the

Eagle-21 System for Unit 1 in operating Cycle 5; and (3) submit software configuration and system modifications, prior to implementation, not consistent with the staff approved Revision 3 of the final Eagle-21 System V&V Report for Sequoyah, which was submitted by letter dated May 8, 1990. The licensee committed to submit the first report within 30 days of Unit 1 reaching approximately 100 percent power. By telephone conference call on October 4, 1990, the licensee committed to extend this to Unit 2 and to the Unit 2 Operating Cycle 5.

3.0 ENVIRONMENTAL CONSIDERATION

These amendments involve a change to a requirement with respect to the installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes to the surveillance requirements. The staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that these amendments involve no significant hazards consideration and there has been no public comment on such finding. Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement nor environmental assessment need be prepared in connection with the issuance of these amendments.

4.0 CONCLUSION

The Commission made a proposed determination that the amendment involves no significant hazards consideration which was published in the Federal Register (55 FR 6119) on February 21, 1990 and consulted with the State of Tennessee. No public comments were received and the State of Tennessee did not have any comments.

The staff has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security nor to the health and safety of the public.

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Dated: October 31, 1990

TABLE 1

TVA LETTERS - NRC REVIEW CHRONOLOGY

Date	Subject	Comment
01/24/90	TS 89-27, Eagle-21 TS Changes	TVA letter
02/26/90	NRC/TVA/Westinghouse Meeting in Rockville, Md.	Meeting
03/01/90	Median Signal Selector - WCAPs 12417/ 12418	TVA letter
03/01/90	Eagle-21 Topical Report - WCAPs 12374/12375	TVA letter
03/13-14/90	NRC Audit in Pittsburgh, PA	NRC Audit, Note 1
04/11/90	Median Signal Selector Testing	TVA letter
04/11/90	Eagle-21 10 CFR 50.59 Evaluation	TVA letter
04/18-20/90	NRC Verification and Validation (V&V) Audit in Pittsburgh, PA	NRC Audit
04/23/90	Setpoint Methodology - WCAPs 11239/ 11626	TVA letter
04/25/90	TS 89-27, Revision 1	TVA letter, Note 3
05/03-04/90	NRC Eagle-21 Installation Audit at Sequoyah Site	NRC Audit
05/04/90	Eagle-21 V&V Completion	TVA letter, Note 2
05/08/90	Eagle-21 Additional Information, Partial Trip Output Board Design	TVA letter, Note 1
05/08/90	Eagle-21 V&V Final Report	TVA letter, Note 2
05/08/90	Eagle-21 Summary Report	TVA letter
05/08/90	Eagle-21 Equipment Qualification WCAPs	TVA letter
05/09/90	Eagle-21 P-8/TTD Design	TVA letter, Note 2