MARKED-UP TECHNICAL SPECIFICATIONS

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B 3/4 3-1	B 3/4 3-1
B 3/4 3-1a	B 3/4 3-1a
-----	B 3/4 3-1b

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	N.A.	N.A
2. Power Range, Neutron Flux		
a. Low Setpoint	≤ 25% of RATED THERMAL POWER	Item 1 ≤ ~~27.1%~~ 24.2% of RATED THERMAL POWER
b. High Setpoint	≤ 109% of RATED THERMAL POWER	Item 2 ≤ ~~111.1%~~ 110.2% of RATED THERMAL POWER
3. Power Range, Neutron Flux High Positive Rate	≤ 5% of RATED THERMAL POWER with a time constant ≥ 2 seconds	Item 3 ≤ ~~6.5%~~ 5.6% of RATED THERMAL POWER with a time constant ≥ 2 seconds
4. Power Range, Neutron Flux High Negative Rate	≤ 5% of RATED THERMAL POWER with a time constant ≥ 2 seconds	Item 4 ≤ ~~6.5%~~ 5.6% of RATED THERMAL POWER with a time constant ≥ 2 seconds
5. Intermediate Range, Neutron Flux	≤ 25% of RATED THERMAL POWER	Item 5 ≤ ~~30.9%~~ 30.6% of RATED THERMAL POWER
6. Source Range, Neutron Flux	≤ 105 counts per second	≤ 1.4 x 105 counts per second
7. Overtemperature ΔT	See Note 1	See Note 2
8. Overpower ΔT	See Note 3	See Note 4
9. Pressurizer Pressure-Low	≥ 1950 psig	Item 6 ≥ ~~1944.4~~ 1947.5 psig
10. Pressurizer Pressure-High	≤ 2385 psig	Item 7 ≤ ~~2390.6~~ 2387.5 psig
11. Pressurizer Water Level-High	≤ ~~92%~~ 90% of instrument span	Item 8 ≤ ~~92.5%~~ 90.2% of instrument span
12. Reactor Coolant Flow-Low	≥ 90% of minimum measured flow** per loop	Item 9 ≥ ~~89.7%~~ 89.8% of minimum measured flow** per loop

**Minimum measured flow is 89,800 gpm per loop for Unit 1 and 90,625 gpm per loop for Unit 2.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
13. Steam Generator Water Level-Low-Low	≥ 7.2% of narrow range instrument span-each steam generator	Item 10 ≥ ~~6.8%~~ 7.0% of narrow range instrument span-each steam generator
Coincident with:		
a. RCS Loop ΔT Equivalent to Power ≤50% RTP	RCS Loop ΔT variable input ≤50% RTP	Item 10a ~~RCS Loop ΔT variable input ≤51.5% RTP~~ 50.7
With a time delay (TD)	≤TD (Note 5)	≤(1.01)TD (Note 5)
Or		
b. RCS Loop ΔT Equivalent to Power >50% RTP (Fix Typo)	RCS Loop ΔT variable input >50% RTP	Item 10a ~~RCS Loop ΔT variable input >51.5% RTP~~ 50.7
With no time delay	TD = 0	TD = 0
14. DELETED		
15. Undervoltage-Reactor Coolant Pumps	≥ 8050 volts-each bus	Item 11 ≥ ~~7730~~ 7877 volts-each bus
16. Underfrequency-Reactor Coolant Pumps	≥ 54.0 Hz - each bus	≥ 53.9 Hz - each bus
17. Turbine Trip		
a. Low Autostop Oil Pressure	≥ 50 psig	≥ 45 psig
b. Turbine Stop Valve Closure	≥ 1% open	≥ 1% open
18. Safety Injection Input from ESF	N.A.	N.A.
19. Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.
20. Reactor Trip Breakers	N.A.	N.A.
21. Automatic Trip and Interlock Logic	N.A.	N.A.

TABLE 2.2-1 (Continued)
REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
22. Reactor Trip System Interlocks		
a. Intermediate Range Neutron Flux, P-6	$\geq 1 \times 10^{-10}$ amps	Item 12 $\geq$ ~~6~~ 8 $\times 10^{-11}$ amps
b. Low Power Reactor Trips Block, P-7		
1) P-10 Input	10% of RATED THERMAL POWER	Item 13 $\geq$ ~~7.9%~~ 8.8%, $\leq$ ~~12.1%~~ 11.2% of RATED THERMAL POWER
2) P-13 Input	$\leq$ 10% RTP Turbine Impulse Pressure Equivalent	Item 14 $\leq$ ~~12.1%~~ 10.2% RTP Turbine Impulse Pressure Equivalent
c. Power Range Neutron Flux, P-8	$\leq$ 35% of RATED THERMAL POWER	Item 15 $\leq$ ~~37.1%~~ 34.2% of RATED THERMAL POWER
d. Power Range Neutron Flux, P-9	$\leq$ 50% of RATED THERMAL POWER	Item 16 $\leq$ ~~52.1%~~ 51.2% of RATED THERMAL POWER
e. Power Range Neutron Flux, P-10	10% of RATED THERMAL POWER	Item 17 $\geq$ ~~7.9%~~ 8.8%, $\leq$ ~~12.1%~~ 11.2% of RATED THERMAL POWER
f. Turbine Impulse Chamber Pressure, P-13	$\leq$ 10% RTP Turbine Impulse Pressure Equivalent	Item 18 $\leq$ ~~12.1%~~ 10.2% RTP Turbine Impulse Pressure Equivalent
23. Seismic Trip	$\leq$ 0.35 g	Item 19 $\leq$ ~~0.40~~ 0.43 g

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

TABLE NOTATIONS

NOTE 1: OVERTEMPERATURE ΔT

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

Where: $\frac{1+\tau_4 S}{1+\tau_5 S}$ = Lead-lag compensator on measured ΔT

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τ_4, τ_5 = Time constants utilized in the lead-lag ~~controller~~ compensator for ΔT, τ_4 = 0 seconds, τ_5 = 0 seconds

Item 21

ΔT_o = LOOP specific Indicated ΔT at RATED THERMAL POWER

K_1 = 1.2

K_2 = 0.0182/°F

Item 20

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

Item 20

τ_1, τ_2 = Time constants utilized in the lead-lag ~~controller~~ compensator for T_{avg}, τ_1 = 30 seconds τ_2 = 4 seconds

T = Average temperature, °F;

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

TABLE NOTATIONS

NOTE 1: (Continued)

T' = Nominal (Loop specific Indicated) T_{avg} at RATED THERMAL POWER Item 21

K_3 = 0.000831/psig

P = Pressurizer pressure, psig

P' = 2235 psig (Nominal RCS operating pressure)

S = Laplace transform operator, S^{-1}

and f_1 (ΔI) 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 - 19% and + 7%, f_1 (ΔI) = 0 (where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER).

(ii) for each percent that the magnitude of ($q_t - q_b$) exceeds - 19%, the ΔT Trip Setpoint shall be automatically reduced by 2.75% of its value at RATED THERMAL POWER.

(iii) for each percent that the magnitude of ($q_t - q_b$) exceeds + 7%, the ΔT Trip Setpoint shall be automatically reduced by 2.38% of its value at RATED THERMAL POWER.

NOTE 2: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than ~~1.0% ΔT span.~~ 0.46% ΔT span for hot leg or cold leg temperature inputs, 0.14% ΔT span for pressurizer pressure input, or 0.19% ΔT span for ΔI inputs.

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TABLE 2.[illegible] (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

TABLE NOTATIONS

NOTE 3: OVERPOWER ΔT

$$\Delta T\left(\frac{1+\tau_4 S}{1+\tau_5 S}\right) \leq \Delta T_0\{K_4 - K_5\left(\frac{\tau_3 S}{1+\tau_3 S}\right) T - K_6 [T-T''] - f_2(\Delta I)\}$$

Where: $\frac{1+\tau_4 S}{1+\tau_5 S}$ = Lead-lag compensator on measured ΔT Item 20

τ_4, τ_5 = Time constants utilized in the lead-lag ~~controller~~ compensator for ΔT, τ_4 = 0 seconds, τ_5 = 0 seconds

ΔT_0 = Loop specific Item 21 Indicated ΔT at RATED THERMAL POWER

K_4 = 1.072

K_5 = 0.0174/°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~~ compensator Item 20 for T_{avg} dynamic compensation

τ_3 = Time constants utilized in the rate-lag ~~controller~~ compensator Item 20 for T_{avg}, τ_3 = 10 secs.

K_6 = 0.00145/°F for T > T", and 0 for T ≤ T"

T = Average temperature, °F

T" = Nominal loop specific Item 23 Indicated T_{avg} at RATED THERMAL POWER

S = Laplace transform operator, s^{-1}

$f_2(\Delta I)$ = 0 for all ΔI

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TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

Item 24

TABLE NOTATIONS

NOTE 4: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than ~~1.0%~~ 0.46% ΔT span for hot leg or cold leg temperature inputs.

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

$$TD = B1(P)^3 + B2(P)^2 + B3(P) + B4$$

Where: P = RCS Loop ΔT Equivalent to Power (%RTP), P ≤ 50% RTP

TD = Time delay for Steam Generator Water Level Low-Low Reactor Trip (in seconds).

B1 = -0.007128

B2 = +0.8099

B3 = -31.40

B4 = +464.1

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2.2.1 REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

INSERT A

The Reactor Trip Setpoint Limits specified in Table 2.2-1 are the nominal values at which the Reactor trips are set for each functional unit. DELETE ~~The Trip Setpoints~~ have been selected to ensure that the reactor core and Reactor Coolant System are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist the Engineered Safety Features Actuation System in mitigating the consequences of accidents. The various reactor trip circuits automatically open the reactor trip breakers whenever a condition monitored by the Reactor Trip System reaches a preset or calculated level. In addition to redundant channels and trains, the design approach provides a Reactor Trip System which monitors numerous system variables, therefore, providing protection system functional diversity. The setpoint for a reactor trip system or interlock function is considered to be adjusted consistent with the nominal value when the "as left" setpoint is within the band allowed for calibration ~~accuracy~~ tolerance. There is a band allowed for calibration ~~accuracy~~ only for those setpoints which use analog hardware. For example, the Power Range, Neutron Flux High setpoint is properly adjusted when it is set at 109% ± 0.3% (0.25% of 120% power span). The setpoints which use digital hardware are set at the nominal value in the system. INSERT B

The Reactor Trip System initiates a Turbine trip signal whenever Reactor trip is initiated. This prevents the reactivity insertion that would otherwise result from excessive Reactor Coolant System cooldown and thus avoids unnecessary actuation of the Engineered Safety Features Actuation System. MOVE PARAGRAPH

INSERT C

To accommodate the instrument drift that may occur between operational tests and the accuracy to which setpoints can be measured and calibrated, Allowable Values for the Reactor Trip Setpoints have been specified in Table 2.2-1. Operation with a trip set less conservative than its Trip Setpoint, but within its specified Allowable Value, is acceptable. INSERT D

The methodology to derive the Trip Setpoints is based upon combining all of the uncertainties in the channels. Inherent to the determination of the Trip Setpoints are the magnitudes of these channel uncertainties. Sensors and other instrumentation utilized in these channels are expected to be capable of operating within the allowances of these uncertainty magnitudes.

Manual Reactor Trip

The Reactor Trip System includes manual Reactor trip capability.

Power Range, Neutron Flux

In each of the Power Range Neutron Flux channels there are two independent bistables, each with its own trip setting used for a High and Low Range trip setting. The Low Setpoint trip provides protection during subcritical and low power operations to mitigate the consequences of a power excursion beginning from low power, and the High Setpoint trip provides protection during power operations to mitigate the consequences of a reactivity excursion from all power levels.

INSERTS FOR TS BASES PAGE B 2-3

BASES — 2.2.1 REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

INSERT A

The Allowable Values are considered the Limiting Safety System Settings (LSSS) as identified in 10 CFR 50.36. The LSSS settings...

INSERT B

The calibration tolerance, after appropriate conversion, should correspond to the rack comparator setting accuracy defined in the latest setpoint study.

INSERT C

Trip Setpoints may be administratively redefined in the conservative direction for several reasons including startup, testing, process error accountability, or even a conservative response for equipment malfunction or inoperability. Some trip functions have historically been redefined at the beginning of each cycle for purposes of startup testing, e.g. Power Range Neutron Flux High and Overtemperature ΔT. Calibration to within the defined calibration tolerance of an administratively redefined, conservative Trip Setpoint is acceptable. Redefinition at full power conditions for these functions is expected and acceptable.

INSERT D

Rack drift in excess of the Allowable Value exhibits the behavior that the rack has not met its allowance. Since there is a small statistical chance that this will happen, an infrequent excessive drift is expected. Rack or sensor drift in excess of the allowance that is more than occasional may be indicative of more serious problems and warrants further investigation.

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	N.A.	R(14)	N.A.	1, 2, 3*, 4*, 5*
2. Power Range, Neutron Flux						
a. High Setpoint	S Item 26	D(2, 4), M(3, 4), Q(4, 6), R24 ~~R~~(4, 5)	Q	N.A.	N.A.	1, 2
b. Low Setpoint	S	R24 ~~R~~(4) Item 27	S/U(1)	N.A.	N.A.	1###, 2
3. Power Range, Neutron Flux, High Positive Rate	N.A.	R24 ~~R~~(4) Item 28	Q	N.A.	N.A.	1, 2
4. Power Range, Neutron Flux, High Negative Rate	N.A.	R24 ~~R~~(4) Item 29	Q	N.A.	N.A.	1, 2
5. Intermediate Range, Neutron Flux	S Item 30	R24 ~~R~~(4, 5)	S/U(1)	N.A.	N.A.	1###, 2
6. Source Range, Neutron Flux	S Item 31	R24 ~~R~~(4, 5)	S/U(1),Q(8)	N.A.	N.A.	2##, 3, 4, 5
7. Overtemperature ΔT	S Item 32	~~R~~ R24	Q	N.A.	N.A.	1, 2
8. Overpower ΔT	S Item 33	~~R~~ R24	Q	N.A.	N.A.	1, 2
9. Pressurizer Pressure-Low	S Item 34	~~R~~ R24	Q	N.A.	N.A.	1
10. Pressurizer Pressure-High	S Item 35	~~R~~ R24	Q	N.A.	N.A.	1, 2
11. Pressurizer Water Level-High	S Item 36	~~R~~ R24	Q	N.A.	N.A.	1
12. Reactor Coolant Flow-Low	S Item 37	~~R~~ R24	Q	N.A.	N.A.	1

TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
13. Steam Generator Water Level-Low-Low						
a. Steam Generator Water Level-Low-Low	S	~~R~~ R24 Item 38	Q	N.A.	N.A.	1, 2
b. RCS Loop ΔT Equivalent to Power	N.A.	~~R~~ R24 Item 39	Q	N.A.	N.A.	1, 2
14. DELETED						
15. Undervoltage-Reactor Coolant Pumps	N.A.	~~R~~ R24 Item 40	N.A.	Q	N.A.	1
16. Underfrequency-Reactor Coolant Pumps	N.A.	~~R~~ R24 Item 41	N.A.	Q	N.A.	1
17. Turbine Trip						
a. Low Fluid Oil Pressure	N.A.	N.A.	N.A.	S/U(1, 9)	N.A.	1
b. Turbine Stop Valve Closure	N.A.	N.A.	N.A.	S/U(1, 9)	N.A.	1
18. Safety Injection Input from ESF	N.A.	N.A.	N.A.	R	N.A	1, 2
19. Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.	N.A.	R	N.A.	1
20. Reactor Trip System Interlocks						
a. Intermediate Range Neutron Flux, P-6	N.A.	R24 ~~R~~(4) Item 42	~~R~~ R24	N.A.	N.A.	2##
b. Low Power Reactor Trips Block, P-7	N.A.	R24 ~~R~~(4) Item 43	~~R~~ R24	N.A.	N.A.	1
c. Power Range Neutron Flux, P-8	N.A.	R24 ~~R~~(4) Item 44	~~R~~ R24	N.A.	N.A.	1

TABLE 4.3.1 (CONTINUED)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
20. Reactor Trip System Interlocks (Continued)						
d. Power Range Neutron Flux, P-9	N.A.	R24 ~~R(4)~~ Item 45	~~R~~ R24	N.A.	N.A.	1
e. Low Setpoint Power Range Neutron Flux, P-10	N.A.	R24 ~~R(4)~~ Item 46	~~R~~ R24	N.A.	N.A.	1, 2
f. Turbine Impulse Chamber Pressure, P-13	N.A.	R24 ~~R~~ Item 47	~~R~~ R24	N.A.	N.A.	1
21. Reactor Trip Breaker	N.A.	N.A.	N.A.	M(7, 10)	N.A.	1, 2, 3*, 4*, 5*
22. Automatic Trip and Interlock Logic	N.A.	N.A.	N.A.	N.A.	M(7)	1, 2, 3*, 4*, 5*
23. Seismic Trip	N.A.	R24 ~~R~~ Item 48	N.A.	~~R~~ R24	~~R~~ M(7)	1, 2
24. Reactor Trip Bypass Breaker	N.A	N.A.	N.A.	M(7,15),R(16)	N.A.	1,2,3*,4*,5*

TABLE 3.3-4

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT		ALLOWABLE VALUES
1. Safety Injection (Reactor Trip, Feedwater Isolation, Start Diesel Generators, Containment Fan Cooler Units, and Component Cooling Water)			
a. Manual Initiation	N.A.		N.A
b. Automatic Actuation Logic and Actuation Relays	N.A.		N.A
c. Containment Pressure-High	≤ 3 psig	Item 49	≤ ~~3.3~~ 3.12 psig
d. Pressurizer Pressure-Low	≥ 1850 psig	Item 50	≥ ~~1844.4~~ 1847.5 psig
e. DELETED			
f. Steam Line Pressure-Low	≥ 600 psig (Note 1)	Item 51	≥ ~~594.6~~ 597.6 psig (Note 1)

TABLE 3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
2. Containment Spray (coincident with SI signal)		
a. Manual Initiation	N.A.	N.A
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A
c. Containment Pressure-High-High	≤ 22 psig	≤ ~~22.3~~ 22.12 psig Item 52
3. Containment Isolation		
a. Phase "A" Isolation		
1) Manual	N.A.	N.A
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.	
b. Phase "B" Isolation		
1) Manual	N.A.	N.A
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A
3) Containment Pressure-High-High	≤ 22 psig	≤ ~~22.3~~ 22.12 psig Item 53

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
3. Containment Isolation (Continued)		
c. Containment Ventilation Isolation		
1) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
2) Deleted		
3) Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.	
4) Containment Ventilation Exhaust Radiation-High (RM-44A and 44B)	Per the ODCP	
4. Steam Line Isolation		
a. Manual	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure-High-High	≤ 22 psig	Item 54 ≤ ~~22.3~~ 22.12 psig
d. Steam Line Pressure-Low	≥ 600 psig (Note 1)	Item 55 ≥ ~~594.6~~ 597.6 psig (Note 1)

TABLE 3.3-4 (continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
e. Negative Steam Line Pressure Rate - High	≤ 100 psi (Note 3)	Item 56 ≤ ~~105.4~~ 102.4 psi (Note 3)
5. Turbine Trip and Feedwater Isolation		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. Steam Generator Water level-High-High	≤ 75% of narrow range instrument span each steam generator.	Item 57 ≤ ~~76.5%~~ 75.2% of narrow range instrument span each steam generator.
6. Auxiliary Feedwater		
a. Manual	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Steam Generator Water Level-Low-Low	≥ 7.2% of narrow range instrument span each steam generator.	Item 58. ≥ ~~6.8%~~ 7.0% of narrow range instrument span each steam generator.
Coincident with:		
1) RCS Loop ΔT Equivalent to Power ≤ 50% RTP	RCS Loop ΔT variable input ≤ 50% RTP	Item 58a RCS Loop ΔT variable input ≤ ~~51.5~~ 50.7 RTP
With a time delay (TD)	≤ TD (Note 2)	≤ (1.01)TD (Note 2)
Or		
2) RCS Loop ΔT Equivalent to Power >50% RTP	RCS Loop ΔT variable input > 50% RTP	Item 58a RCS Loop ΔT variable input ≥ ~~51.5~~ 50.7 RTP
With no time delay	TD = 0	TD = 0
d. Undervoltage - RCP	≥ 8050 volts	Item 59 ≥ ~~7730~~ 7877 volts
e. Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.	

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
7. Loss of Power (4.16 kV Emergency Bus Undervoltage)		
a. First Level		
1) Diesel Start	≥ 0 volts with a ≤ 0.8 second time delay and ≥ 2583 volts with a ≤ 10 second time delay	≥ 0 volts with a ≤ 0.8 second time delay and ≥ 2583 volts with ≤ 10 second time delay
2) Initiation of Load Shed	One relay ≥ 0 volts with a ≤ 4 second time delay and ≥ 2583 volts with a ≤ 25 second time delay with one relay ≥ 2870 volts, instantaneous	One relay ≥ 0 volts with a ≤ 4 second time delay and ≥ 2583 volts with a ≤ 25 second time delay with one relay ≥ 2870 volts, instantaneous
b. Second Level		
1) Diesel Start	≥ 3785 volts with a ≤ 10 second time delay	≥ 3785 volts with a ≤ 10 second time delay
2) Initiation of Load Shed	≥ 3785 volts with a ≤ 20 second time delay	≥ 3785 volts with a ≤ 20 second time delay
8. Engineered Safety Features Actuation System Interlocks		
a. Pressurizer Pressure, P-11	≤ 1915 psig	Item 60 ≤ ~~1920.6~~ 1917.5 psig
b. DELETED		
c. Reactor Trip, P-4	N.A.	N.A.

NOTE 1: Time constants utilized in the lead-lag ~~controller~~ compensator for Steam Pressure - Low are τ_1 = 50 seconds and τ_2 = 5 seconds. Item 20

NOTE 2: Steam Generator Water Level Low-Low Trip Time Delay

$TD = B1(P)^3 + B2(P)^2 + B3(P) + B4$

Where: P = RCS Loop ΔT Equivalent to Power (%RTP), P ≤ 50% RTP

TD = Time delay for Steam Generator Water Level Low-Low (in seconds)

B1 = -0.007128
B2 = +0.8099
B3 = -31.40
B4 = +464.1

NOTE 3: Time constants utilized in the rate-lag ~~controller~~ compensator for Negative Steam Line Pressure Rate-High are τ_3 = 50 seconds and τ_4 = 50 seconds. Item 20

TABLE 4.3-2

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALI-BRATION	CHANNEL OPERA-TIONAL TEST	TRIP ACTUATING DEVICE OPERA-TIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Safety Injection, (Reactor Trip Feedwater Isolation, Start Diesel Generators, Containment Fan Cooler Units, and Component Cooling Water)								
a. Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2, 3, 4
c. Containment Pressure-High	S	R24 R Item 61	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3, 4
d. Pressurizer Pressure-Low	S	R24 R Item 62	Q	N.A	N.A.	N.A.	N.A.	1, 2, 3
e. DELETED								
f. Steam Line Pressure-Low	S	R24 R Item 63	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
2. Containment Spray (coincident with SI signal)								
a. Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2, 3, 4
c. Containment Pressure-High-High	S	R24 R Item 64	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3, 4

TABLE [illegible] (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALI-BRATION	CHANNEL OPERA-TIONAL TEST	TRIP ACTUATING DEVICE OPERA-TIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
3. Containment Isolation								
a. Phase "A" Isolation								
1) Manual	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2, 3, 4
3) Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
b. Phase "B" Isolation								
1) Manual	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2, 3, 4
3) Containment Pressure-High-High	S	R24 R Item 65	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3, 4
c. Containment Ventilation Isolation								
1) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2, 3, 4
2) Deleted								
3) Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
4) Containment Ventilation Exhaust Radiation-High (RM-44A and 44B)	S	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3, 4

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALI-BRATION	CHANNEL OPERA-TIONAL TEST	TRIP ACTUATING DEVICE OPERA-TIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
4. Steam Line Isolation								
a. Manual	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2, 3
c. Containment Pressure-High-High	S	R24 R Item 66	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
d. Steam Line Pressure-Low	S	R24 R Item 67	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
e. Negative Steam Line Pressure Rate-High	S	R24 R Item 68	Q	N.A.	N.A.	N.A.	N.A.	3(3)
5. Turbine Trip and Feedwater Isolation								
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2
b. Steam Generator Water Level-High-High	S	R24 R Item 69	Q	N.A.	N.A.	N.A.	N.A.	1, 2
6. Auxiliary Feedwater								
a. Manual	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2, 3
c. Steam Generator Water Level-Low-Low								
1) Steam Generator Water Level-Low-Low	S	R24 R Item 70	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3(5)
2) RCS Loop ΔT Equivalent to Power	N.A.	R24 R Item 71	Q	N.A.	N.A.	N.A.	N.A.	1, 2

TABLE [illegible] (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALI-BRATION	CHANNEL OPERA-TIONAL TEST	TRIP ACTUATING DEVICE OPERA-TIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
6. Auxiliary Feedwater (Continued)								
d. Undervoltage - RCP	N.A.	R24 ~~R~~	Item 72 N.A.	R24 ~~R~~	N.A.	N.A.	N.A.	1
e. Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
7. Loss of Power								
a. 4.16 kV Emergency Bus Level 1	N.A.	R	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
b. 4.16 kV Emergency Bus Level 2	N.A.	R	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
8. Engineered Safety Feature Actuation System Interlocks								
a. Pressurizer Pressure, P-11	N.A.	R24 ~~R~~	Item 73 Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
b. Deleted								
c. Reactor Trip, P-4	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3

TABLE NOTATIONS

(1) Each train shall be tested at least every 62 days on a STAGGERED TEST BASIS.
(2) For the Containment Ventilation Exhaust Radiation-High monitor only, a CHANNEL FUNCTIONAL TEST shall be performed at least once every 31 days.
(3) Trip function automatically blocked above P-11 (Pressurizer Pressure Interlock) setpoint and is automatically blocked below P-11 when Safety Injection on Steam Line Pressure-Low is not blocked.
(4) Deleted.
(5) For Mode 3, the Trip Time Delay associated with the Steam Generator Water Level-Low-Low channel must be less than or equal to 464.1 seconds.

ITEM 74
2 pages, four inserts

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

The OPERABILITY of the Reactor Trip System and Engineered Safety Features Actuation System (ESFAS) 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 and sufficient redundancy is maintained to permit a channel to be out of service for testing or maintenance consistent with maintaining an appropriate level of reliability of the Reactor Protection and Engineered Safety Features instrumentation, and (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. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and supplements to that report. Surveillance intervals and out-of-service times were determined based on maintaining an appropriate level of reliability of the Reactor Protection System.

The Process Protection System is designed to permit any one channel to be tested and maintained at power in a bypassed mode. If a channel has been bypassed for any purpose, the bypass is continuously indicated in the control room as required by applicable codes and standards. As an alternative to testing in the bypass mode, testing in the trip mode is also possible and permitted.

The ESFAS ~~Engineered Safety Features Actuation System~~ senses selected plant parameters and determines whether or not predetermined limits are being exceeded. If they are, the signals are combined into logic matrices sensitive to combinations indicative of various accidents, events, and transients. Once the required logic combination is completed, the system sends actuation signals to those engineered safety features components whose aggregate function best serves the requirements of the condition. As an example, the following actions may be initiated by the ESFAS ~~Engineered Safety Features Actuation System~~ to mitigate the consequences of a steam line break or loss of coolant accident: (1) safety injection pumps start and automatic valves position, (2) Reactor trip, (3) feedwater isolation, (4) startup of the emergency diesel generators, (5) containment spray pumps start and automatic valves position, (6) containment isolation, (7) steam line isolation, (8) Turbine trip, (9) auxiliary feedwater pumps start and automatic valve position, (10) containment fan cooler units start, and (11) component cooling water pumps start and automatic valves position.

The ESFAS ~~Engineered Safety Feature Actuation System~~ Instrumentation Trip Setpoints specified in Table 3.3-4 are the nominal values at which the trips are set for each functional unit. If the functional unit is based on analog hardware, the setpoint is considered to be adjusted consistent with the nominal value when the "as left" setpoint is within the band allowed for calibration ~~accuracy~~ tolerance. For all setpoints in digital hardware, the setpoints are set at the nominal values.

INSERT E

INSERT F

INSERT FOR TS BASES PAGE B 3/4 3-1

BASES — 3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM and ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

INSERT E

The Allowable Values are considered to be the Limiting Safety System Settings (LSSS) as identified in 10 CFR 50.36 and have been selected to mitigate the consequences of accidents.

INSERT F

The calibration tolerance, after appropriate conversion, should correspond to the rack comparator setting accuracy defined in the latest setpoint study.

REACTOR PROTECTION SYSTEM and ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

Insert G To accommodate the instrument drift that may occur between operational tests and the accuracy to which setpoints can be measured and calibrated, Allowable Values for the setpoints have been specified in Table 3.3-4. Operation with setpoints less conservative than the Trip Setpoint, but within the Allowable Value, is acceptable. Insert H

The methodology to derive the Trip Setpoints is based upon combining all of the uncertainties in the channel. Inherent to the determination of the Trip Setpoints are the magnitudes of these channel uncertainties. Sensor and rack instrumentation utilized in these channels are expected to be capable of operating within the allowances of these uncertainty magnitudes.

Fix TYPO: non-

ESF response times specified in Table 3.3-5, which include sequential operation of the RWST and VCT valves (Table Notations 4 and 5), are based on values assumed in the ~~on~~-LOCA safety analyses. These analyses take credit for injection of borated water from the RWST. Injection of borated water is assumed not to occur until the VCT charging pump suction isolation valves are closed following opening of the RWST charging pump suction isolation valves. When the sequential operation of the RWST and VCT valves is not included in the response times (Table Notation 7), the values specified are based on the LOCA analyses. The LOCA analyses takes credit for injection flow regardless of the source. Verification of the response times specified in Table 3.3-5 will assure that the assumptions used for the LOCA and non-LOCA analyses with respect to the operation of the VCT and RWST valves are valid.

For slave relays in the ESF actuation system circuit that are Potter & Brumfield type MDR relays, the SLAVE RELAY TEST is performed on a refueling frequency. The test frequency is based on relay reliability assessments presented in WCAP-13878, "Reliability Assessment of Potter and Brumfield MDR Series Relays," WCAP-13900, "Extension of Slave Relay Surveillance Test Intervals," and WCAP-14117, "Reliability Assessment of Potter and Brumfield MDR Series Relays." These reliability assessments are relay specific and apply only to Potter and Brumfield MDR series relays. Note that for normally energized applications, the relays may have to be replaced periodically in accordance with the guidance given in WCAP-13878 for MDR relays.

Undervoltage protection will generate a loss of power diesel generator start in the event a loss of voltage or degraded voltage condition occurs. The diesel generators provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. The first level undervoltage relays (FLURs) detect the loss of bus voltage (less than 69% bus voltage). The second level undervoltage relays (SLURS) provide a second level of undervoltage protection which protects all Class 1E loads from short or long term degradation in the offsite power system. The SLUR allowable value is the minimum steady state voltage needed on the 4160 volt vital bus to ensure adequate voltage is available for safety related equipment at the 4160 volt, 480 volt, and 120 volt levels.

INSERTS FOR TS BASES PAGE B 3/4 3-1a

BASES — 3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM and ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

INSERT G

The ESFAS Trip Setpoints may be administratively redefined in the conservative direction for several reasons including startup, testing, process error accountability, or even a conservative response for equipment malfunction or inoperability. ESFAS functions are not historically redefined at the beginning of each cycle for purposes of startup or testing as several Reactor Trip functions are. However, calibration to within the defined calibration tolerance of an administratively redefined, conservative Trip Setpoint is acceptable. Redefinition at full power conditions for these functions is expected and acceptable.

INSERT H

Rack drift in excess of the Allowable Value exhibits the behavior that the rack has not met its allowance. Since there is a small statistical chance that this will happen, an infrequent excessive drift is expected. Rack or sensor drift in excess of the allowance that is more than occasional may be indicative of more serious problems and warrants further investigation.

PROPOSED REVISED TS PAGES

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	N.A.	N.A
2. Power Range, Neutron Flux		
a. Low Setpoint	≤ 25% of RATED THERMAL POWER	≤ 26.2% of RATED THERMAL POWER
b. High Setpoint	≤ 109% of RATED THERMAL POWER	≤ 110.2% of RATED THERMAL POWER
3. Power Range, Neutron Flux High Positive Rate	≤ 5% of RATED THERMAL POWER with a time constant ≥ 2 seconds	≤ 5.6% of RATED THERMAL POWER with a time constant ≥ 2 seconds
4. Power Range, Neutron Flux High Negative Rate	≤ 5% of RATED THERMAL POWER with a time constant ≥ 2 seconds	≤ 5.6% of RATED THERMAL POWER with a time constant ≥ 2 seconds
5. Intermediate Range, Neutron Flux	≤ 25% of RATED THERMAL POWER	≤ 30.6% of RATED THERMAL POWER
6. Source Range, Neutron Flux	≤ 10^5 counts per second	≤ 1.4 x 10^5 counts per second
7. Overtemperature ΔT	See Note 1	See Note 2
8. Overpower ΔT	See Note 3	See Note 4
9. Pressurizer Pressure-Low	≥ 1950 psig	≥ 1947.5 psig
10. Pressurizer Pressure-High	≤ 2385 psig	≤ 2387.5 psig
11. Pressurizer Water Level-High	≤ 90% of instrument span	≤ 90.2% of instrument span
12. Reactor Coolant Flow-Low	≥ 90% of minimum measured flow** per loop	≥ 89.8% of minimum measured flow** per loop

**Minimum measured flow is 89,800 gpm per loop for Unit 1 and 90,625 gpm per loop for Unit 2.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
13. Steam Generator Water Level-Low-Low	≥ 7.2% of narrow range instrument span-each steam generator	≥ 7.0% of narrow range instrument span-each steam generator
Coincident with:		
a. RCS Loop ΔT Equivalent to Power ≤50% RTP	RCS Loop ΔT variable input ≤50% RTP	RCS Loop ΔT variable input ≤50.7% RTP
With a time delay (TD)	≤TD (Note 5)	≤(1.01)TD (Note 5)
Or		
b. RCS Loop ΔT Equivalent to Power >50% RTP	RCS Loop ΔT variable input >50% RTP	RCS Loop ΔT variable input >50.7% RTP
With no time delay	TD = 0	TD = 0
14. DELETED		
15. Undervoltage-Reactor Coolant Pumps	≥ 8050 volts-each bus	≥ 7877 volts-each bus
16. Underfrequency-Reactor Coolant Pumps	≥ 54.0 Hz - each bus	≥ 53.9 Hz - each bus
17. Turbine Trip		
a. Low Autostop Oil Pressure	≥ 50 psig	≥ 45 psig
b. Turbine Stop Valve Closure	≥ 1% open	≥ 1% open
18. Safety Injection Input from ESF	N.A.	N.A.
19. Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.
20. Reactor Trip Breakers	N.A.	N.A.
21. Automatic Trip and Interlock Logic	N.A.	N.A.

TABLE 2.2-1 (Continued)
REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
22. Reactor Trip System Interlocks		
a. Intermediate Range Neutron Flux, P-6	$\geq 1 \times 10^{-10}$ amps	$\geq 8 \times 10^{-11}$ amps
b. Low Power Reactor Trips Block, P-7		
1) P-10 Input	10% of RATED THERMAL POWER	$\geq$ 8.8%, $\leq$ 11.2% of RATED THERMAL POWER
2) P-13 Input	$\leq$ 10% RTP Turbine Impulse Pressure Equivalent	$\leq$ 10.2% RTP Turbine Impulse Pressure Equivalent
c. Power Range Neutron Flux, P-8	$\leq$ 35% of RATED THERMAL POWER	$\leq$ 36.2% of RATED THERMAL POWER
d. Power Range Neutron Flux, P-9	$\leq$ 50% of RATED THERMAL POWER	$\leq$ 51.2% of RATED THERMAL POWER
e. Power Range Neutron Flux, P-10	10% of RATED THERMAL POWER	$\geq$ 8.8%, $\leq$ 11.2% of RATED THERMAL POWER
f. Turbine Impulse Chamber Pressure, P-13	$\leq$ 10% RTP Turbine Impulse Pressure Equivalent	$\leq$ 10.2% RTP Turbine Impulse Pressure Equivalent
23. Seismic Trip	$\leq$ 0.35 g	$\leq$ 0.43 g

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

TABLE NOTATIONS

NOTE 1: OVERTEMPERATURE ΔT

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

Where: $\frac{1+\tau_4 S}{1+\tau_5 S}$ = Lead-lag compensator on measured ΔT

τ_4, τ_5 = Time constants utilized in the lead-lag compensator for ΔT, τ_4 = 0 seconds, τ_5 = 0 seconds

ΔT_o = Loop specific indicated ΔT at RATED THERMAL POWER

K_1 = 1.2

K_2 = 0.0182/°F

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

τ_1, τ_2 = Time constants utilized in the lead-lag compensator for T_{avg}, τ_1 = 30 seconds τ_2 = 4 seconds

T = Average temperature, °F;

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

TABLE NOTATIONS

NOTE 1: (Continued)

T' = Nominal loop specific indicated T_{avg} at RATED THERMAL POWER

K_3 = 0.000831/psig

P = Pressurizer pressure, psig

P' = 2235 psig (Nominal RCS operating pressure)

S = Laplace transform operator, S^{-1}

and f_1 (ΔI) 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 - 19% and + 7%, f_1 (ΔI) = 0 (where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER).

(ii) for each percent that the magnitude of ($q_t - q_b$) exceeds - 19%, the ΔT Trip Setpoint shall be automatically reduced by 2.75% of its value at RATED THERMAL POWER.

(iii) for each percent that the magnitude of ($q_t - q_b$) exceeds + 7%, the ΔT Trip Setpoint shall be automatically reduced by 2.38% of its value at RATED THERMAL POWER.

NOTE 2: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 0.46% ΔT span for hot leg or cold leg temperature inputs, 0.14% ΔT span for pressurizer pressure input, or 0.19% ΔT span for ΔI inputs.

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

TABLE NOTATIONS

NOTE 3: OVERPOWER ΔT

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

Where: $\frac{1+\tau_4 S}{1+\tau_5 S}$ = Lead-lag compensator on measured ΔT

τ_4, τ_5 = Time constants utilized in the lead-lag compensator for ΔT, τ_4 = 0 seconds, τ_5 = 0 seconds

ΔT_o = Loop specific indicated ΔT at RATED THERMAL POWER

K_4 = 1.072

K_5 = 0.0174/°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 compensator for T_{avg} dynamic compensation

τ_3 = Time constants utilized in the rate-lag compensator for T_{avg}, τ_3 = 10 secs.

K_6 = 0.00145/°F for T > T", and 0 for T ≤ T"

T = Average temperature, °F

T" = Nominal loop specific indicated T_{avg} at RATED THERMAL POWER

S = Laplace transform operator, s^{-1}

$f_2(\Delta I)$ = 0 for all ΔI

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

TABLE NOTATIONS

NOTE 4: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 0.46% ΔT span for hot leg or cold leg temperature inputs.

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

$$TD = B1(P)^3 + B2(P)^2 + B3(P) + B4$$

Where: P = RCS Loop ΔT Equivalent to Power (%RTP), P ≤ 50% RTP

TD = Time delay for Steam Generator Water Level Low-Low Reactor Trip (in seconds).

B1 = -0.007128

B2 = +0.8099

B3 = -31.40

B4 = +464.1

2.2.1 REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Trip Setpoint Limits specified in Table 2.2-1 are the nominal values at which the Reactor trips are set for each functional unit. The Allowable Values are considered the Limiting Safety System Settings (LSSS) as identified in 10 CFR 50.36. The LSSS settings have been selected to ensure that the reactor core and Reactor Coolant System are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist the Engineered Safety Features Actuation System in mitigating the consequences of accidents. The various reactor trip circuits automatically open the reactor trip breakers whenever a condition monitored by the Reactor Trip System reaches a preset or calculated level. In addition to redundant channels and trains, the design approach provides a Reactor Trip System which monitors numerous system variables, therefore, providing protection system functional diversity.

The Reactor Trip System initiates a Turbine trip signal whenever Reactor trip is initiated. This prevents the reactivity insertion that would otherwise result from excessive Reactor Coolant System cooldown and thus avoids unnecessary actuation of the Engineered Safety Features Actuation System.

The setpoint for a reactor trip system or interlock function is considered to be adjusted consistent with the nominal value when the "as left" setpoint is within the band allowed for calibration tolerance. There is a band allowed for calibration tolerance only for those setpoints which use analog hardware. For example, the Power Range, Neutron Flux High setpoint is properly adjusted when it is set at 109% ± 0.3% (0.25% of 120% power span). The calibration tolerance, after appropriate conversion, should correspond to the rack comparator setting accuracy defined in the latest setpoint study. The setpoints which use digital hardware are set at the nominal value in the system.

Trip Setpoints may be administratively redefined in the conservative direction for several reasons including startup, testing, process error accountability, or even a conservative response for equipment malfunction or inoperability. Some trip functions have historically been redefined at the beginning of each cycle for purposes of startup testing, e.g. Power Range Neutron Flux High and Overtemperature ΔT. Calibration to within the defined calibration tolerance of an administratively redefined, conservative Trip Setpoint is acceptable. Redefinition at full power conditions for these functions is expected and acceptable.

To accommodate the instrument drift that may occur between operational tests and the accuracy to which setpoints can be measured and calibrated, Allowable Values for the Reactor Trip Setpoints have been specified in Table 2.2-1. Operation with a trip set less conservative than its Trip Setpoint, but within its specified Allowable Value, is acceptable. Rack drift in excess of the Allowable Value exhibits the behavior that the rack has not met its allowance. Since there is a small statistical chance that this will happen, an infrequent excessive drift is expected. Rack or sensor drift in excess of the allowance that is more than occasional may be indicative of more serious problems and warrants further investigation.

The methodology to derive the Trip Setpoints is based upon combining all of the uncertainties in the channels. Inherent to the determination of the Trip Setpoints are the magnitudes of these channel uncertainties. Sensors and other instrumentation utilized in these channels are expected to be capable of operating within the allowances of these uncertainty magnitudes.

Manual Reactor Trip

The Reactor Trip System includes manual Reactor trip capability.

Power Range, Neutron Flux

In each of the Power Range Neutron Flux channels there are two independent bistables, each with its own trip setting used for a High and Low Range trip setting. The Low Setpoint trip provides protection during subcritical and low power operations to mitigate the consequences of a power excursion beginning from low power, and the High Setpoint trip provides protection during power operations to mitigate the consequences of a reactivity excursion from all power levels.

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	N.A.	R(14)	N.A.	1, 2, 3*, 4*, 5*
2. Power Range, Neutron Flux						
a. High Setpoint	S	D(2, 4), M(3, 4), Q(4, 6), R24(4, 5)	Q	N.A.	N.A.	1, 2
b. Low Setpoint	S	R24(4)	S/U(1)	N.A.	N.A.	1###, 2
3. Power Range, Neutron Flux, High Positive Rate	N.A.	R24(4)	Q	N.A.	N.A.	1, 2
4. Power Range, Neutron Flux, High Negative Rate	N.A.	R24(4)	Q	N.A.	N.A.	1, 2
5. Intermediate Range, Neutron Flux	S	R24(4, 5)	S/U(1)	N.A.	N.A.	1###, 2
6. Source Range, Neutron Flux	S	R24(4, 5)	S/U(1),Q(8)	N.A.	N.A.	2##, 3, 4, 5
7. Overtemperature ΔT	S	R24	Q	N.A.	N.A.	1, 2
8. Overpower ΔT	S	R24	Q	N.A.	N.A.	1, 2
9. Pressurizer Pressure-Low	S	R24	Q	N.A.	N.A.	1
10. Pressurizer Pressure-High	S	R24	Q	N.A.	N.A.	1, 2
11. Pressurizer Water Level-High	S	R24	Q	N.A.	N.A.	1
12. Reactor Coolant Flow-Low	S	R24	Q	N.A.	N.A.	1

TABLE 4 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
13. Steam Generator Water Level-Low-Low						
a. Steam Generator Water Level-Low-Low	S	R24	Q	N.A.	N.A.	1, 2
b. RCS Loop ΔT Equivalent to Power	N.A.	R24	Q	N.A.	N.A.	1, 2
14. DELETED						
15. Undervoltage-Reactor Coolant Pumps	N.A.	R24	N.A.	Q	N.A.	1
16. Underfrequency-Reactor Coolant Pumps	N.A.	R24	N.A.	Q	N.A.	1
17. Turbine Trip						
a. Low Fluid Oil Pressure	N.A.	N.A.	N.A.	S/U(1, 9)	N.A.	1
b. Turbine Stop Valve Closure	N.A.	N.A.	N.A.	S/U(1, 9)	N.A.	1
18. Safety Injection Input from ESF	N.A.	N.A.	N.A.	R	N.A	1, 2
19. Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.	N.A.	R	N.A.	1
20. Reactor Trip System Interlocks						
a. Intermediate Range Neutron Flux, P-6	N.A.	R24(4)	R24	N.A.	N.A.	2##
b. Low Power Reactor Trips Block, P-7	N.A.	R24(4)	R24	N.A.	N.A.	1
c. Power Range Neutron Flux, P-8	N.A.	R24(4)	R24	N.A.	N.A.	1

TABLE 4.3-2 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
20. Reactor Trip System Interlocks (Continued)						
d. Power Range Neutron Flux, P-9	N.A.	R24(4)	R24	N.A.	N.A.	1
e. Low Setpoint Power Range Neutron Flux, P-10	N.A.	R24(4)	R24	N.A.	N.A.	1, 2
f. Turbine Impulse Chamber Pressure, P-13	N.A.	R24	R24	N.A.	N.A.	1
21. Reactor Trip Breaker	N.A.	N.A.	N.A.	M(7, 10)	N.A.	1, 2, 3*, 4*, 5*
22. Automatic Trip and Interlock Logic	N.A.	N.A.	N.A.	N.A.	M(7)	1, 2, 3*, 4*, 5*
23. Seismic Trip	N.A.	R24	N.A.	R24	M(7)	1, 2
24. Reactor Trip Bypass Breaker	N.A	N.A.	N.A.	M(7,15), R(16)	N.A.	1,2,3*,4*,5*

TABLE 3.3-4

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Safety Injection (Reactor Trip, Feedwater Isolation, Start Diesel Generators, Containment Fan Cooler Units, and Component Cooling Water)		
a. Manual Initiation	N.A.	N.A
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A
c. Containment Pressure-High	≤ 3 psig	≤ 3.12 psig
d. Pressurizer Pressure-Low	≥ 1850 psig	≥ 1847.5 psig
e. DELETED		
f. Steam Line Pressure-Low	≥ 600 psig (Note 1)	≥ 597.6 psig (Note 1)

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
2. Containment Spray (coincident with SI signal		
a. Manual Initiation	N.A.	N.A
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A
c. Containment Pressure-High-High	≤ 22 psig	≤ 22.12 psig
3. Containment Isolation		
a. Phase "A" Isolation		
1) Manual	N.A.	N.A
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A
3) Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.	
b. Phase "B" Isolation		
1) Manual	N.A.	N.A
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A
3) Containment Pressure-High-High	≤ 22 psig	≤ 22.12 psig

TABLE 3.3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
3. Containment Isolation (Continued)		
c. Containment Ventilation Isolation		
1) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
2) Deleted		
3) Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.	
4) Containment Ventilation Exhaust Radiation-High (RM-44A and 44B)	Per the ODCP	
4. Steam Line Isolation		
a. Manual	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure-High-High	≤ 22 psig	≤ 22.12 psig
d. Steam Line Pressure-Low	≥ 600 psig (Note 1)	≥ 597.6 psig (Note 1)

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
e. Negative Steam Line Pressure Rate - High	≤ 100 psi (Note 3)	≤ 102.4 psi (Note 3)
5. Turbine Trip and Feedwater Isolation		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. Steam Generator Water level-High-High	≤ 75% of narrow range instrument span each steam generator.	≤ 75.2% of narrow range instrument span each steam generator.
6. Auxiliary Feedwater		
a. Manual	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Steam Generator Water Level-Low-Low	≥ 7.2% of narrow range instrument span each steam generator.	≥ 7.0% of narrow range instrument span each steam generator.
Coincident with:		
1) RCS Loop ΔT Equivalent to Power ≤ 50% RTP	RCS Loop ΔT variable input ≤ 50% RTP	RCS Loop ΔT variable input ≤ 50.7% RTP
With a time delay (TD)	≤ TD (Note 2)	≤ (1.01)TD (Note 2)
Or		
2) RCS Loop ΔT Equivalent to Power >50% RTP	RCS Loop ΔT variable input > 50% RTP	RCS Loop ΔT variable input > 50.7% RTP
With no time delay	TD = 0	TD = 0
d. Undervoltage - RCP	≥ 8050 volts	≥ 7877 volts
e. Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.	

TABLE 3.3-4 (Continued)
ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
7. Loss of Power (4.16 kV Emergency Bus Undervoltage)		
a. First Level		
1) Diesel Start	≥ 0 volts with a ≤ 0.8 second time delay and ≥ 2583 volts with a ≤ 10 second time delay One relay	≥ 0 volts with a ≤ 0.8 second time delay and > 2583 volts with ≤ 10 second time delay One relay
2) Initiation of Load Shed	≥ 0 volts with a ≤ 4 second time delay and ≥ 2583 volts with a ≤ 25 second time delay with one relay ≥ 2870 volts, instantaneous	≥ 0 volts with a ≤ 4 second time delay and > 2583 volts with a ≤ 25 second time delay with one relay ≥ 2870 volts, instantaneous
b. Second Level		
1) Diesel Start	≥ 3785 volts with a ≤ 10 second time delay	≥ 3785 volts with a ≤ 10 second time delay
2) Initiation of Load Shed	≥ 3785 volts with a ≤ 20 second time delay	≥ 3785 volts with a ≤ 20 second time delay
8. Engineered Safety Features Actuation System Interlocks		
a. Pressurizer Pressure, P-11	≤ 1915 psig	≤ 1917.5 psig
b. DELETED		
c. Reactor Trip, P-4	N.A.	N.A.

NOTE 1: Time constants utilized in the lead-lag compensator for Steam Pressure - Low are τ_1 = 50 seconds and τ_2 = 5 seconds.

NOTE 2: Steam Generator Water Level Low-Low Trip Time Delay

$$TD = B1(P)^3 + B2(P)^2 + B3(P) + B4$$

Where: P = RCS Loop ΔT Equivalent to Power (%RTP), P ≤ 50% RTP
TD = Time delay for Steam Generator Water Level Low-Low (in seconds)
B1 = -0.007128
B2 = +0.8099
B3 = -31.40
B4 = +464.1

NOTE 3: Time constants utilized in the rate-lag compensator for Negative Steam Line Pressure Rate-High are τ_3 = 50 seconds and τ_4 = 50 seconds.

TABLE 4.3-2

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALI-BRATION	CHANNEL OPERA-TIONAL TEST	TRIP ACTUATING DEVICE OPERA-TIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Safety Injection, (Reactor Trip Feedwater Isolation, Start Diesel Generators, Containment Fan Cooler Units, and Component Cooling Water)								
a. Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2, 3, 4
c. Containment Pressure-High	S	R24	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3, 4
d. Pressurizer Pressure-Low	S	R24	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
e. DELETED								
f. Steam Line Pressure-Low	S	R24	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
2. Containment Spray (coincident with SI signal)								
a. Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2, 3, 4
c. Containment Pressure-High-High	S	R24	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3, 4

TABLE 4.3[illegible] (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALI-BRATION	CHANNEL OPERA-TIONAL TEST	TRIP ACTUATING DEVICE OPERA-TIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
3. Containment Isolation								
a. Phase "A" Isolation								
1) Manual	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2, 3, 4
3) Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
b. Phase "B" Isolation								
1) Manual	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2, 3, 4
3) Containment Pressure-High-High	S	R24	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3, 4 |
c. Containment Ventilation Isolation								
1) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2, 3, 4
2) Deleted								
3) Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
4) Containment Ventilation Exhaust Radiation-High (RM-44A and 44B)	S	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3, 4

TABLE 4.3-2 (Continued)
ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALI-BRATION	CHANNEL OPERA-TIONAL TEST	TRIP ACTUATING DEVICE OPERA-TIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
4. Steam Line Isolation								
a. Manual	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2, 3
c. Containment Pressure-High-High	S	R24	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
d. Steam Line Pressure-Low	S	R24	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
e. Negative Steam Line Pressure Rate-High	S	R24	Q	N.A.	N.A.	N.A.	N.A.	3(3)
5. Turbine Trip and Feedwater Isolation								
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2
b. Steam Generator Water Level-High-High	S	R24	Q	N.A.	N.A.	N.A.	N.A.	1, 2
6. Auxiliary Feedwater								
a. Manual	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	R	1, 2, 3
c. Steam Generator Water Level-Low-Low								
1) Steam Generator Water Level-Low-Low	S	R24	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3(5)
2) RCS Loop ΔT Equivalent to Power	N.A.	R24	Q	N.A	N.A	N.A	N.A	1, 2

TABLE 4.3-2 (Continued)
ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALI-BRATION	CHANNEL OPERA-TIONAL TEST	TRIP ACTUATING DEVICE OPERA-TIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
6. Auxiliary Feedwater (Continued)								
d. Undervoltage - RCP	N.A.	R24	N.A.	R24	N.A.	N.A.	N.A.	1
e. Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
7. Loss of Power								
a. 4.16 kV Emergency Bus Level 1	N.A.	R	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
b. 4.16 kV Emergency Bus Level 2	N.A.	R	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
8. Engineered Safety Feature Actuation System Interlocks								
a. Pressurizer Pressure, P-11	N.A.	R24	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
b. DELETED								
c. Reactor Trip, P-4	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3

TABLE NOTATIONS

(1) Each train shall be tested at least every 62 days on a STAGGERED TEST BASIS.
(2) For the Containment Ventilation Exhaust Radiation - High monitor only, a CHANNEL FUNCTIONAL TEST shall be performed at least once every 31 days.
(3) Trip function automatically blocked above P-11 (Pressurizer Pressure Interlock) setpoint and is automatically blocked below P-11 when Safety Injection on Steam Line Pressure-Low is not blocked.
(4) Deleted.
(5) For Mode 3, the Trip Time Delay associated with the Steam Generator Water Level-Low-Low channel must be less than or equal to 464.1 seconds.

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

The OPERABILITY of the Reactor Trip System and Engineered Safety Features Actuation System (ESFAS) 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 and sufficient redundancy is maintained to permit a channel to be out of service for testing or maintenance consistent with maintaining an appropriate level of reliability of the Reactor Protection and Engineered Safety Features instrumentation, and (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. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and supplements to that report. Surveillance intervals and out-of-service times were determined based on maintaining an appropriate level of reliability of the Reactor Protection System.

The Process Protection System is designed to permit any one channel to be tested and maintained at power in a bypassed mode. If a channel has been bypassed for any purpose, the bypass is continuously indicated in the control room as required by applicable codes and standards. As an alternative to testing in the bypass mode, testing in the trip mode is also possible and permitted.

The ESFAS senses selected plant parameters and determines whether or not predetermined limits are being exceeded. If they are, the signals are combined into logic matrices sensitive to combinations indicative of various accidents, events, and transients. Once the required logic combination is completed, the system sends actuation signals to those engineered safety features components whose aggregate function best serves the requirements of the condition. As an example, the following actions may be initiated by the ESFAS to mitigate the consequences of a steam line break or loss of coolant accident: (1) safety injection pumps start and automatic valves position, (2) Reactor trip, (3) feedwater isolation, (4) startup of the emergency diesel generators, (5) containment spray pumps start and automatic valves position, (6) containment isolation, (7) steam line isolation, (8) Turbine trip, (9) auxiliary feedwater pumps start and automatic valve position, (10) containment fan cooler units start, and (11) component cooling water pumps start and automatic valves position.

The ESFAS Instrumentation Trip Setpoints specified in Table 3.3-4 are the nominal values at which the trips are set for each functional unit. The Allowable Values are considered to be the Limiting Safety System Settings (LSSS) as identified in 10 CFR 50.36 and have been selected to mitigate the consequences of accidents. If the functional unit is based on analog hardware, the setpoint is considered to be adjusted consistent with the nominal value when the "as left" setpoint is within the band allowed for calibration tolerance.

REACTOR PROTECTION SYSTEM and ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

The calibration tolerance, after appropriate conversion, should correspond to the rack comparator setting accuracy defined in the latest setpoint study. For all setpoints in digital hardware, the setpoints are set at the nominal values.

The ESFAS Trip Setpoints may be administratively redefined in the conservative direction for several reasons including startup, testing, process error accountability, or even a conservative response for equipment malfunction or inoperability. ESFAS functions are not historically redefined at the beginning of each cycle for purposes of startup or testing as several Reactor Trip functions are. However, calibration to within the defined calibration tolerance of an administratively redefined, conservative Trip Setpoint is acceptable. Redefinition at full power conditions for these functions is expected and acceptable.

To accommodate the instrument drift that may occur between operational tests and the accuracy to which setpoints can be measured and calibrated, Allowable Values for the setpoints have been specified in Table 3.3-4. Operation with setpoints less conservative than the Trip Setpoint, but within the Allowable Value, is acceptable. Rack drift in excess of the Allowable Value exhibits the behavior that the rack has not met its allowance. Since there is a small statistical chance that this will happen, an infrequent excessive drift is expected. Rack or sensor drift in excess of the allowance that is more than occasional may be indicative of more serious problems and warrants further investigation.

The methodology to derive the Trip Setpoints is based upon combining all of the uncertainties in the channel. Inherent to the determination of the Trip Setpoints are the magnitudes of these channel uncertainties. Sensor and rack instrumentation utilized in these channels are expected to be capable of operating within the allowances of these uncertainty magnitudes.

ESF response times specified in Table 3.3-5, which include sequential operation of the RWST and VCT valves (Table Notations 4 and 5), are based on values assumed in the non-LOCA safety analyses. These analyses take credit for injection of borated water from the RWST. Injection of borated water is assumed not to occur until the VCT charging pump suction isolation valves are closed following opening of the RWST charging pump suction isolation valves. When the sequential operation of the RWST and VCT valves is not included in the response times (Table Notation 7), the values specified are based on the LOCA analyses. The LOCA analyses takes credit for injection flow regardless of the source. Verification of the response times specified in Table 3.3-5 will assure that the assumptions used for the LOCA and non-LOCA analyses with respect to the operation of the VCT and RWST valves are valid.

For slave relays in the ESF actuation system circuit that are Potter & Brumfield type MDR relays, the SLAVE RELAY TEST is performed on a refueling frequency. The test frequency is based on relay reliability assessments presented in WCAP-13878, "Reliability Assessment of Potter and Brumfield MDR Series Relays," WCAP-13900, "Extension of Slave Relay Surveillance Test Intervals," and WCAP-14117, "Reliability Assessment of Potter and Brumfield MDR Series Relays." These reliability assessments are relay specific and apply only to Potter and Brumfield MDR series relays. Note that for normally energized applications, the relays may have to be replaced periodically in accordance with the guidance given in WCAP-13878 for MDR relays.

REACTOR PROTECTION SYSTEM and ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

Undervoltage protection will generate a loss of power diesel generator start in the event a loss of voltage or degraded voltage condition occurs. The diesel generators provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. The first level undervoltage relays (FLURs) detect the loss of bus voltage (less than 69% bus voltage). The second level undervoltage relays (SLURs) provide a second level of undervoltage protections which protects all Class 1E loads from short or long term degradation in the offsite power system. The SLUR allowable value is the minimum steady state voltage needed on the 4160 volt vital bus to ensure adequate voltage is available for safety related equipment at the 4160 volt, 480 volt, and 120 volt levels.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS FOR EACH PROPOSED TS CHANGE

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 1, 2, 3, 4, 13, 15, 16, 17, 26, 27, 28, 29, 43, 44, 45, 46

TECHNICAL SPECIFICATIONS
2.2.1
3/4.3.1

POWER RANGE NEUTRON FLUX

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the power range neutron flux allowable values in TS 2.2.1, Table 2.2-1, and revise the surveillance requirements in TS 3/4.3.1, Table 4.3-1, to change the surveillance frequency from R, at least once per 18 months, to R24, at least once per REFUELING INTERVAL (nominal 24 months, maximum 30 months).

TABLE 2 - POWER RANGE NEUTRON FLUX

PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Setpoints		(no changes proposed)		
Safety Analysis Limits		(no changes proposed)		
Allowable Values (Table 2.2-1)	1	power range neutron flux, low setpoint	≤27.1% rated thermal power (RTP)	≤26.2% RTP
	2	power range neutron flux, high setpoint	≤111.1%	≤110.2%
	3	power range neutron flux high positive rate	≤6.5%	≤5.6%
	4	power range neutron flux high negative rate	≤6.5%	≤5.6%
	13	low power reactor trips block, P-7, P-10 input	≥7.9% ≤12.1%	≥8.8% ≤11.2%
	15	power range neutron flux, P-8	≤37.1%	≤36.2%
	16	power range neutron flux, P-9	≤52.1	≤51.2

TABLE 2 - POWER RANGE NEUTRON FLUX				
PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
	17	power range neutron flux, P-10	≥7.9% ≤12.1%	≥8.8% ≤11.2%
Channel Calibration (Table 4.3-1)	26	power range neutron flux high setpoint	R	R24
	27	power range neutron flux low setpoint	R	R24
	28	power range neutron flux high positive rate	R	R24
	29	power range neutron flux high negative rate	R	R24
	43	low power reactor trips block, P-7	R	R24
	44	power range neutron flux, P-8	R	R24
	45	power range neutron flux, P-9	R	R24
	46	low setpoint power range neutron flux, P-10	R	R24
Channel Operational Test (Table 4.3-1)	43	low power reactor trips block, P-7	R	R24
	44	power range neutron flux, P-8	R	R24
	45	power range neutron flux, P-9	R	R24
	46	low setpoint power range neutron flux, P-10	R	R24

B. BACKGROUND

The power range neutron flux instrument outputs are compared to a secondary heat balance every day that Diablo Canyon is at power, as required by the TS. The secondary heat balance determines the actual reactor power output, and the result is compared to the power range neutron flux indications. If the power range instrument readings differ from the heat balance by 2 percent reactor power or more, the power range instrument is adjusted as required by the TS. Due to this daily heat balance, the setpoint uncertainty analysis did not include an allowance for instrument drift. The daily secondary heat balance will be required during

the extended fuel cycle. Power range neutron flux bistable trip setpoints are checked every three months in a channel operational test (COT), and this check will also continue during the extended fuel cycle.

C. SAFETY EVALUATION

This evaluation is applicable to the power range neutron flux level trips, interlocks, and the power range neutron flux rate trips. Due to the daily heat balance, the existing setpoint uncertainty analysis did not include an allowance for instrument drift. Since the daily secondary heat balance will be required during the extended fuel cycle, it is not necessary to allow for increased instrument drift, and a drift was not statistically determined for the power range neutron flux instruments. The power range neutron flux rate trip uncertainty analysis does not consider instrument drift because the use of the derivative for rate eliminates steady-state errors such as process measurement accuracy, sensor calibration, sensor temperature, and sensor drift errors.

The channel statistical allowance (CSA) associated with this channel has been calculated to be 4.88 percent span for the neutron flux - high and low setpoints (this uncertainty also applies to the interlocks P-8, P-9 and P-10). The power range neutron flux - high positive rate and high negative rate reactor trip functions have a calculated uncertainty of 1.35 percent span. These uncertainties are the same as the previously calculated values for DCPP, except that Revision 5 of WCAP-11082 expresses the uncertainties to two significant figures after the decimal while Revision 2 uses one significant figure after the decimal. The input errors to the calculation did not change, and the algorithm for the error combination was the same. Therefore, there is no change in the method or the results of the calculation.

The margin to the safety analysis limit is 2.62 percent span for the power range neutron flux - high setpoint reactor trip and 3.45 percent span for the power range neutron flux - low setpoint reactor trip. The power range neutron flux rate trips are not used in the plant safety analyses and, therefore, have an undefined margin to a safety limit. Based on the current safety analysis limits and nominal trip setpoints, there are no TS setpoint changes or safety analysis limit changes required for the power range neutron flux reactor trip functions.

All of the new, proposed allowable values are more restrictive than the previous values (see Table 2). The differences between the trip or interlock setpoints and the allowable values are equivalent to the sum of rack drift

and rack Measuring & Test Equipment (M&TE) errors in accordance with WCAP-11082, Revision 5, Section 4.3.

Section E of Attachment A provides a safety evaluation applicable to extending the surveillance intervals from 18 to 24 months for the power range neutron flux instruments. Based on that evaluation, PG&E has determined that the power range neutron flux drift is not affected by an increased calibration interval and that the channel calibration interval can be extended for a period up to 30 months consistent with the 24-month fuel cycle.

A review of the Plant Information Management System (PIMS) component history for the P-7, P-8, P-9, and P-10 bistable portions of the power range nuclear instrumentation channels did not identify any problems with the calibrations or the quarterly COTs performed since December 1989 (the extent of component history in PIMS). Based on the successful performance of the COTs to date, it is proposed that the frequency for these COTs be extended to R24.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed changes in Table 2.2-1 revise the allowable values as noted.

The proposed changes to TS Table 4.3-1 extend the frequency for surveillances from at least once per 18 months, to at least once per refueling interval (i.e., 24 months nominal, 30 months maximum).

The following evaluation is the basis for the no significant hazards consideration determination.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

   The proposed allowable value changes in Table 2.2-1 are all in the more restrictive direction and, therefore, do not adversely affect the probability or consequences of accidents.

   The increased surveillance intervals in Table 4.3-1 do not change the manner in which the plant is operated or the way in which surveillance tests are performed. Evaluation of the specified components indicates they will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

   The proposed allowable value changes in Table 2.2-1 are more restrictive and, therefore, have no effect on the possible types of accidents in the facility.

   The surveillance history of the neutron flux instruments indicates that the specified components will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

   Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

   The allowable value changes proposed in Table 2.2-1 are more restrictive and, therefore, do not reduce safety margins.

   There is no safety analysis impact associated with increasing the surveillance interval for the neutron flux instruments. This change will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

   Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 5, 12, 30, 42

TECHNICAL SPECIFICATIONS
2.2.1
3/4.3.1

INTERMEDIATE RANGE NEUTRON FLUX

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the intermediate range neutron flux allowable values in TS 2.2.1, Table 2.2-1 and revise the surveillance requirements in TS 3/4.3.1, Table 4.3-1, to change the surveillance frequency from R, at least once per 18 months, to R24, at least once per REFUELING INTERVAL (nominal 24 months, maximum 30 months).

TABLE 3 - INTERMEDIATE RANGE NEUTRON FLUX

PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Setpoints		(no changes proposed)		
Safety Analysis Limits		(no changes proposed)		
Allowable Values (Table 2.2-1)	5	intermediate range neutron flux	≤30.9% RTP	≤30.6% RTP
	12	intermediate range neutron flux, P-6	≥6E-11 amps	≥8E-11 amps
Channel Calibration (Table 4.3-1)	30	intermediate range neutron flux	R	R24
	42	intermediate range neutron flux, P-6	R	R24
Channel Operational Test (Table 4.3-1)	42	intermediate range neutron flux, P-6	R	R24

B. BACKGROUND

The input sensors to the intermediate range (IR) neutron flux instrument are not required to be calibrated by the DCPP TS. The remainder of the instrument (called the rack) is required to be calibrated every 18 months

and must receive a COT within 31 days before startup. As input to the statistical evaluation of instrument rack calibration accuracy and drift, PG&E compiled as-left/as-found calibration test data. These data were based on a review of completed test procedures, including those executed at refueling outages, as well as any midcycle tests that were conducted due to instrument channel problems or modifications.

C. SAFETY EVALUATION

The rack calibration accuracy (as-left data) was compared to procedural tolerances and was statistically evaluated to verify that the distribution could be treated as normal and was consistent with the allowance incorporated in the statistical uncertainty calculation. Second, the difference between as-found and as-left data was used to statistically calculate projected rack drift for a 30-month calibration interval at a 95 percent probability and at a 95 percent confidence level, including an assessment of drift time dependence. This step included the evaluation of as-left/as-found data for IR neutron flux racks (log amplifiers) in both units over a period of approximately 6 fuel cycles.

In addition, all data were evaluated for normality and the existence of outliers, which were eliminated where indicated through the use of accepted statistical tests or the identification of mechanistic causes. One IR instrument calibration was eliminated by the outlier test resulting in the drift data pool for the IR log amplifier decreasing from 408 data points to 390 data points. The IR bistable drift was similarly analyzed. These statistical evaluations resulted in a combined IR log amplifier/bistable drift allowance of ± 2.05 percent rated thermal power (RTP) span for a 30-month calibration interval. This drift uncertainty was less than the existing rack drift allowance of 4.2 percent RTP span in WCAP-11082, Revision 2 (expressed to two significant digits, as 4.17 percent, in WCAP-11082, Revision 5). To be conservative, the existing rack drift (4.17 percent RTP span) was used as an input to determine the IR channel statistical allowance (CSA) using the Westinghouse setpoint methodology from WCAP-11082, Revision 2.

Along with instrument drift, all other channel uncertainties of the IR instrument, including rack, M&TE (all of which were adjusted for the channel's log function), and process effects for normal environmental conditions were included in the evaluation. The evaluation of instrument uncertainties is based on the currently installed hardware as defined by DCPP calibration procedures.

The CSA associated with the IR neutron flux channel has been calculated to be 11.15 percent RTP span for the IR neutron flux high setpoint. The uncertainty is greater than the previously calculated value in WCAP-11082, Revision 2 (9.8 percent RTP span), because of the effect of the log function on the uncertainties. The algorithm for the error combination was the same. The IR neutron flux level trip is not used in the plant safety analyses and, therefore, has no defined margin to a safety limit. Based on the absence of a safety analysis limit and the nominal trip setpoint value, there is no TS setpoint change for the IR neutron flux reactor trip function.

All of the new, proposed allowable values are more restrictive than the previous values (see Table 3). The difference between the trip setpoint and the allowable value is equivalent to the sum of rack drift and rack Measuring & Test Equipment (M&TE) errors in accordance with WCAP-11082, Revision 5, Section 4.3.

Section E of Attachment A provides a safety evaluation applicable to extending the surveillance interval from 18 to 24 months for the IR neutron flux instruments. Based on that evaluation, PG&E has determined that the IR neutron flux drift will not be increased beyond analysis values by an increased calibration interval and that the channel calibration interval can be extended for a period up to 30 months consistent with the 24-month fuel cycle.

A review of the Plant Information Management System (PIMS) component history for the P-6 bistable portion of the IR nuclear instrumentation channels did not identify any problems with the calibrations or the quarterly COTs performed since December 1989 (the extent of component history in PIMS). Based on the successful performance of the COTs to date, it is proposed that the frequency for this functional unit's COT be extended to R24.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed changes in Table 2.2-1 revise the allowable values as noted. The proposed changes in Table 4.3-1 extend the frequency for surveillances from at least once per 18 months, to at least once per refueling interval (i.e., 24 months nominal, 30 months maximum).

The following evaluation is the basis for the no significant hazards consideration determination.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

The proposed allowable value changes in Table 2.2-1 are all in the more restrictive direction and, therefore, do not adversely affect the probability or consequences of accidents.

The increased surveillance intervals in Table 4.3-1 do not change the manner in which the plant is operated or the way in which surveillance tests are performed. Evaluation of the specified components indicates they will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

The proposed allowable value changes in Table 2.2-1 are more restrictive and, therefore, have no effect on the possible types of accidents in the facility.

The surveillance history of the IR neutron flux instruments indicates that the specified components will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

The allowable value changes proposed in Table 2.2-1 are more restrictive and, therefore, do not reduce safety margins.

There is no safety analysis impact associated with increasing the surveillance interval for the IR neutron flux instruments. This change will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEM 31

TECHNICAL SPECIFICATION 3/4.3.1

SOURCE RANGE NEUTRON FLUX

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the surveillance requirement in TS 3/4.3.1, Table 4.3-1, for the source range neutron flux instrument surveillance to change the surveillance frequency from R, at least once per 18 months, to R24, at least once per REFUELING INTERVAL (nominal 24 months, maximum 30 months).

TABLE 4 - SOURCE RANGE NEUTRON FLUX				
PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Setpoints		(no changes proposed)		
Safety Analysis Limits		(no changes proposed)		
Allowable Values		(no changes proposed)		
Channel Calibration (Table 4.3-1)	31	source range neutron flux	R	R24

B. BACKGROUND

The input sensors to the source range (SR) neutron flux instrument are not required to be calibrated by the DCPP TS. The remainder of the instrument (called the rack) is required to be calibrated every 18 months and must receive a channel operational test within 31 days before startup. As input to the statistical evaluation of instrumentation rack calibration accuracy and drift, PG&E compiled as-left/as-found calibration test data. These data were based on a review of completed test procedures, including those executed at refueling outages as well as any midcycle tests that were conducted due to instrument channel problems, modifications, or plant startups.

C. SAFETY EVALUATION

The evaluation of this data was twofold as was done for the other RTS/ESFAS input parameters. First, the rack calibration accuracy (as-left data) was compared to procedural tolerances and was statistically evaluated to verify that the distribution could be treated as normal and was consistent with the allowance incorporated in the statistical uncertainty calculation. Second, the difference between as-found and as-left data was used to statistically calculate projected rack drift for a 30-month calibration interval at a 95 percent probability and at a 95 percent confidence level, including an assessment of drift time dependence. This step included the evaluation of as-left/as-found data for source range neutron flux racks in both units over a period of approximately 5 fuel cycles.

In addition, all data were evaluated for normality and the existence of outliers. None of the 273 calibration data points were eliminated. The rack drift distribution was found to not fit a normal distribution model and instead a normal approximation of a binomial distribution was fit to the data. The source range bistable drift was similarly evaluated. These statistical evaluations resulted in a combined SR log circuit/bistable drift allowance of ± 1.66 percent counts per second (CPS) span for a 30-month calibration interval. This drift uncertainty was less than the rack drift allowance of 3.0 percent CPS span used in WCAP-11082, Revision 2. To be conservative, the current rack drift allowance was used as an input to determine the channel statistical allowance (CSA) using the Westinghouse setpoint methodology from WCAP-11082, Revision 2.

Along with instrument drift, all other channel uncertainties of the SR instrument including rack, M&TE (all of which were adjusted for the channel's log function), and process effects for normal environmental conditions were included in the evaluation. The evaluation of instrument uncertainties is based on the currently installed hardware as defined by DCPP calibration procedures.

The CSA associated with the SR neutron flux channel has been calculated to be 12.25 percent span for the SR neutron flux high setpoint. The uncertainty is greater than the previously calculated value (10.7 percent span) in WCAP-11082, Revision 2, because of the effect of the log function on the uncertainties. The algorithm for the error combination was the same.

The allowable value for the SR neutron flux, high, was evaluated in accordance with WCAP-11082, Revision 5, Section 4.3, and was determined to be satisfactory as-is. The SR neutron flux level trip is not

used in the plant safety analyses and, therefore, has no defined margin to a safety limit. Based on the absence of a safety analysis limit and the nominal trip setpoint value, there are no TS setpoint or allowable value changes for the SR neutron flux instrument.

Based on the above evaluation, combined with the evaluation in Section E of Attachment A, PG&E has determined that the SR neutron flux drift will not be increased beyond analysis values by an increased calibration interval and that channel calibration interval can be extended for a period up to 30 months consistent with the 24-month fuel cycle.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed change in TS Table 4.3-1 extends the frequency for surveillance from at least once per 18 months, to at least once per refueling interval (i.e., 24 months nominal, 30 months maximum).

The following evaluation is the basis for the no significant hazards consideration determination.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

   The increased surveillance interval in Table 4.3-1 does not change the manner in which the plant is operated or the way in which surveillance tests are performed. Evaluation of the specified component indicates it will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

   Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

   The surveillance history of the source range neutron flux instruments indicates that the specified components will continue to effectively perform their design functions for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

There is no safety analysis impact associated with increasing the surveillance interval for the source range neutron flux instrument. This change will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 20, 21, 22, 32
OVERTEMPERATURE ΔT

ITEMS 20, 21, 23, 24, 33
OVERPOWER ΔT

ITEMS 10a, 58a, 39, 71
RCS LOOP ΔT EQUIVALENT POWER

TECHNICAL SPECIFICATIONS
2.2.1
3/4.3.1
3/4.3.2

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would: (1) revise the notes in TS 2.2.1, Table 2.2-1, and TS 3/4.3.2, Table 3.3-4; (2) revise the allowable values for overtemperature ΔT, overpower ΔT, and reactor coolant system (RCS) loop ΔT equivalent to power; and (3) revise the surveillance requirements in TS 3/4.3.1, Table 4.3-1, and TS 3/4.3.2, Table 4.3-2, for overtemperature ΔT, overpower ΔT, and RCS loop ΔT equivalent to power to change the surveillance frequency from R, at least once per 18 months, to R24, at least once per REFUELING INTERVAL (nominal 24 months, maximum 30 months).

TABLE 5 - OVERTEMPERATURE AND OVERPOWER ΔT

PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Setpoints		(no changes proposed)		
Safety Analysis Limits		(no changes proposed)		
Allowable Values (Table 2.2-1)	10a	RCS loop ΔT equivalent to power	≤51.5% RTP	≤50.7% RTP
	22	overtemperature ΔT, Note 2	1.0% ΔT span	0.46%, 0.14%, and 0.19%, ΔT span, as noted

TABLE 5 - OVERTEMPERATURE AND OVERPOWER ΔT				
PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
	24	overpower ΔT	1.0% ΔT span	0.46%
Allowable Values (Table 3.3-4)	58a	SG water level, RCS loop ΔT equivalent to power	≤51.5%	≤50.7%
Channel Calibration (Table 4.3-1)	32	overtemperature ΔT	R	R24
	33	overpower ΔT	R	R24
	39	SG water level, RCS loop ΔT equivalent to power	R	R24
Channel Calibration (Table 4.3-2)	71	AFW, SG water level low-low, RCS loop ΔT equivalent to power	R	R24
Text Clarification (Table 2.2-1)	20	overtemperature and overpower ΔT, Notes 1 and 3 (Note: Table 3.3-4 as well)	(text change only)	
	21	overtemperature and overpower ΔT, Notes 1 and 3	(text change only)	
	23	overpower ΔT, Note 3	(text change only)	

B. BACKGROUND

Several changes were made to the methods used to calculate the overtemperatureΔT, overpowerΔT, and RCS loop ΔT equivalent to power channel uncertainties since the completion of WCAP-11082, Revision 2. Higher than expected hot leg streaming effects were noted during startup following the Unit 1 sixth refueling outage in 1994. To account for the streaming effects, Westinghouse evaluated the overtemperatureΔT and overpowerΔT channel uncertainties using a more comprehensive approach, as documented in WCAP-11082, Revision 5. The burndown of low leakage core designs over the length of the cycle and the subsequent impact on hot leg streaming, is addressed in this evaluation.

With low leakage core designs, beginning of life (BOL) power shapes produce higher flux levels in the center of the core, resulting in

correspondingly higher temperatures at the center of the core when compared to outer core temperatures. Over the life of the core the high centered flux will level off, and the radial distribution of the power begins to even out over the core. This affects the temperature streaming in the hot legs, causing the indicated average T_{hot} and the indicated ΔT to decrease; this is referred to as the "burndown effect." The hot leg temperature streaming variation over core life and the burndown effect are assumed to be present in the future extended cycle cores.

Since the total core power (as determined by secondary side power calorimetric) remains at 100 percent rated thermal power (RTP), the temperature changes seen in the hot leg are a result of streaming changes and not a real decrease in core power. If ΔT_o were normalized to a higher indicated ΔT at BOL, a decrease in ΔT would build false margin into the overtemperatureΔT and overpowerΔT trips. That is, the trip channel may measure a ΔT equivalent to 99 percent RTP when the calorimetric shows power to be 100 percent RTP. Therefore, the burndown effects were treated as biases (they demonstrate a preferential direction). Based on the DCPP procedures, ΔT_o is re-normalized if the indicated ΔT changes by 1 percent RTP (approximately 0.6°F). The uncertainty calculation, therefore, includes a ΔT burndown bias of 1 percent RTP.

A similar effect is seen in terms of T_{avg}. That is, if T' and T" were set to the loop-specific indicated T_{avg} values at BOL, a decrease in the indicated T_{avg} due to changes in hot leg streaming over the cycle would create false margin. Therefore, a burndown bias is also applicable to the T_{avg} portion of the overtemperatureΔT and overpowerΔT trips. Based on DCPP procedures, T' and T" will be reset if the indicated T_{avg} changes by 1.0°F. A T_{avg} burndown bias of 1.0°F is, therefore, included in the uncertainty calculations.

Several other changes have been made to the uncertainty calculation method for these trips in order to better reflect the normalization of these channels. First, the cold leg streaming bias on T_{cold} is effectively eliminated when ΔT_o, T', and T" are normalized and, therefore, was deleted from the calculation. In addition, the hot leg streaming process measurement accuracy (PMA) term was eliminated by including the burndown effects. With normalization, this term is inherent in the indication of the burndown effect. The normalization on a loop-specific basis also eliminates the need to account for the resistance temperature detector (RTD) calibration accuracy explicitly, and the RTD drift is inherently included in the burndown effects. Therefore, these terms were not included. However, to account for the accuracy to which the trips can be normalized to real power conditions

based on the secondary side power measurement, an allowance of 2.0 percent RTP was included as a random PMA term.

C. SAFETY EVALUATION

The twofold statistical analyses of loop ΔT instruments for an extended cycle were not performed for the ΔT instruments as was done for other RTS/ESFAS instruments. As was already noted, loop ΔT_o equivalent to 100 percent RTP is set to loop-specific values at BOL and is re-normalized if the indicated ΔT changes by 1 percent RTP (approximately 0.6°F). In addition, T' and T" are set to the loop-specific indicated T_{avg} values at BOL and, based on DCPP procedures, T' and T" are reset if the indicated T_{avg} changes by 1.0°F. The check of these parameters for re-normalization is performed each quarter. Since the validity of the protection functions are ensured by the quarterly checks, the statistical analysis of the ΔT instrument drift for 24 months was not performed.

The pressurizer pressure protection system channel uncertainties were included as inputs to the overtemperature ΔT trip uncertainty calculation. The parameter errors are consistent with the values determined in the pressurizer pressure channel statistical allowance (CSA) calculations and include instrument drift, sensor, rack, M&TE, and process effects for normal environmental conditions. The evaluation of instrument uncertainties was based on the currently installed hardware as defined by DCPP calibration procedures. Vendor specifications were used as appropriate.

The rack M&TE error is based on the M&TE performance currently in use at the plant, as defined in the calibration procedures. Using the above mentioned criteria and the Westinghouse methodology for evaluating channel uncertainties, the following total channel uncertainties (for 30 months) and associated channel margins were calculated:

Overtemperature ΔT trip	
CSA	7.51 percent span
Channel Margin	0.49 percent span
Overpower ΔT trip	
CSA	3.99 percent span
Channel Margin	0.90 percent span

RCS Loop ΔT Equivalent to Power

CSA	3.13 percent span
Channel Margin	2.90 percent span

Based on the current safety analysis limits and nominal trip setpoints, there are no TS setpoint changes or safety analysis limit changes required for the overtemperatureΔT, overpowerΔT and RCS Loop ΔT trip equivalent to power functions.

The allowable values for the overtemperature ΔT (Item 22) and overpower ΔT (Item 24) and RCS loop ΔT (Items 10a and 58a) are proposed to be changed consistent with the methodology of WCAP-11082, Revision 5. The allowable value for Item 22 is specified in Note 2 to Table 2.2-1. The Note is proposed to be changed to read: "The channel's maximum trip setpoint shall not exceed its computed trip setpoint by more than 0.46 percent ΔT span for the hot leg or cold leg temperature inputs, 0.14 percent ΔT span for the pressurizer pressure input, or 0.19 percent ΔT span for ΔI inputs." The allowable value for Item 24 is specified in Note 4 to Table 2.2-1. The Note is proposed to be changed to read: "The channel's maximum trip setpoint shall not exceed its computed trip setpoint by more than 0.46 percent ΔT span for hot leg or cold leg temperature inputs." The allowable values for Items 10a and 58a are proposed to be changed to 50.7 percent of rated thermal power. The differences between the trip setpoints and the allowable values are equivalent to the sum of rack drift and rack M&TE errors in accordance with WCAP-11082, Revision 5, Section 4.3.

The overtemperature ΔT, overpower ΔT, and RCS loop ΔT equivalent to power allowable value changes are in the more restrictive direction (the amount of allowance for error is smaller than the previous allowance, see Table 5), and are consistent with the WCAP-11082, Revision 5, methodology.

Other proposed changes to Notes 1 and 3 (Items 20, 21, and 23) involve terminology and clarifying language and, therefore, have no safety significance.. The term "compensator" is proposed in place of "controller" to better describe signal processing in the racks. The term "loop specific" is used to better define the processing that occurs for each individual RCS loop. The term "equivalent to power" is added for two items to maintain consistency in the TS for all items which refer to RCS loop ΔT equivalent to power. These items are administrative changes only, and do not affect the design, operation, or testing of the plant.

Based on the above, combined with the evaluation in Section E of Attachment A, PG&E has determined that the calibration intervals (surveillances) for the overtemperature ΔT, overpower ΔT and RCS loop ΔT equivalent to power trip functions can be extended for 30 months consistent with the 24-month fuel cycle.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed changes to Tables 4.3-1 and 4.3-2 extend the frequency for surveillances from at least once per 18 months, to at least once per refueling interval (i.e., 24 months nominal, 30 months maximum).

The proposed changes to Table 3.3-4 and Notes 2 and 4 in Table 2.2-1 change allowable values in the more restrictive direction, and the proposed changes to Notes 1 and 3 in Table 2.2-1 revise terminology and clarify language.

The following evaluation is the basis for the no significant hazards consideration determination.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

   The increased surveillance intervals for the overtemperatureΔT, overpowerΔT, and RCS loop ΔT equivalent to power instruments in Tables 4.3-1 and 4.3-2 do not change the manner in which the plant is operated or the way in which surveillance tests are performed. Evaluation of the specified components indicates they will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

   The proposed note and allowable value changes are more restrictive or are administrative and do not affect probability or consequences of accidents.

   Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

The surveillance history of the overtemperatureΔT, overpowerΔT, and RCS loop ΔT equivalent to power instruments indicate that the specified components will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Additionally, the note and allowable value changes do not affect the types of possible accidents.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

There are no safety analysis impacts associated with increasing the surveillance interval for the overtemperatureΔT, overpowerΔT, and RCS loop ΔT equivalent to power instruments. The changes will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Likewise, the note and allowable value changes do not adversely affect safety margins.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 9, 37

TECHNICAL SPECIFICATIONS
2.2.1
3/4.3.1

REACTOR COOLANT SYSTEM LOSS OF FLOW - LOW

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the reactor coolant system (RCS) loss of flow - low allowable value in TS 2.2.1, Table 2.2-1, and revise the reactor coolant flow - low surveillance requirement in TS 3/4.3.1, Table 4.3-1, to change the surveillance frequency from R, at least once per 18 months, to R24, at least once per REFUELING INTERVAL (nominal 24 months, maximum 30 months).

TABLE 6 - RCS LOSS OF FLOW - LOW

PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Setpoints		(no changes proposed)		
Safety Analysis Limits		RCS minimum measured flow (MMF)	87% MMF	85% MMF
Allowable Values (Table 2.2-1)	9	reactor coolant flow low	≥89.7%	≥89.8%
Channel Calibration (Table 4.3-1)	37	reactor coolant flow low	R	R24

B. BACKGROUND

The RCS loss of flow-low protection system uses Rosemount differential pressure transmitters and the Eagle 21 digital processing system to detect a loss of flow-low condition in any RCS loop and initiate protective action (i.e., a reactor trip). Prior to the recently completed Units 1 and 2 seventh refueling outages (1R7 and 2R7) outages, there were 18 Barton Model 764 transmitters and 6 Rosemount 1153HD5 transmitters installed in DCPP Units 1 and 2 for the RCS loss of flow-low trip. During 1R7 and 2R7, all remaining Barton transmitters in the RCS flow channels were replaced by

Rosemount transmitters. Therefore, the evaluation for RCS loss of flow-low was performed only for Rosemount transmitters.

As input to the Westinghouse statistical evaluation of instrument calibration accuracy and drift, PG&E compiled as-left/as-found calibration test data for the Rosemount transmitters. These data were based on a review of completed test procedures, including those executed at refueling outages as well as any midcycle tests that were conducted due to instrument channel problems or modifications. The evaluation of these data was twofold as was done for the other RTS/ESFAS instrumentation.

C. SAFETY EVALUATION

All of the Rosemount transmitter data were evaluated for normality and the existence of outliers. One calibration data set was removed from the drift data pool because of a mechanistic failure (due to a technician error). There were approximately 250 drift data points in the remaining data set. The statistical evaluation of these data resulted in a ±0.6 percent ΔP span drift allowance for a 30-month calibration interval. The drift uncertainty was used as an input to determine the channel statistical allowance (CSA) using the Westinghouse setpoint methodology. The correlation coefficient of drift and calibration interval was 0.14, implying insignificant drift correlation with time. The setpoint evaluation is based on calibration of the flow transmitters using a precision flow calorimetric at the beginning of each fuel cycle.

Along with instrument drift, the determination of all other channel uncertainties, including sensor, rack, M&TE, and process effects for normal environmental conditions is included in the evaluation. The evaluation of instrument uncertainties is based on the currently installed hardware as defined in DCPP calibration procedures. Vendor specifications were used as appropriate.

Westinghouse evaluated the safety analysis limit for the RCS loss of flow setpoint and concluded that the safety analysis limit can be changed to 85 percent minimum measured flow (MMF). This evaluation and conclusion are discussed in more detail in Attachment A, response to Generic Letter 91-04 Question 4.

The channel statistical allowance (CSA) was calculated for both Units 1 and 2 (WCAP-11082, Revision 5). The setpoint uncertainty calculation for both units took into account the RCS loss of flow-low setpoint of greater than or equal to 90 percent MMF. Based on this setpoint, there is margin to the

revised safety analysis limit of 85 percent MMF. Therefore, no setpoint change is required to be implemented to the TS Table 2.2-1.

Because of the change in setpoint methodology, there is a proposed change in the allowable value to greater than or equal to 89.8 percent MMF in the Table 2.2-1 (Item 9) in order to support an extended surveillance of up to 30 months. The allowable value change is in the more restrictive direction (the amount of allowance for error is smaller than the previous allowance) and is consistent with the WCAP-11082, Revision 5, methodology.

Section E of Attachment A provides a safety evaluation applicable to extending the surveillance interval from 18 to 24 months for the RCS loss of flow instruments. Based on the above evaluation and the evaluation in Attachment A, PG&E has determined that the calibration surveillance interval for Item 9 can be extended to 30 months to support a 24-month fuel cycle.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed change in Table 2.2-1 revises the allowable value as noted.

The proposed change in Table 4.3-1 extends the frequency for surveillance from at least once per 18 months, to at least once per refueling interval (i.e., 24 months nominal, 30 months maximum).

These changes are supported by a change in the safety analysis limit from 87 to 85 percent of MMF.

The following evaluation is the basis for the no significant hazards consideration determination.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

   Westinghouse has evaluated the safety analysis limit for the RCS loss of flow-low setpoint and has determined that the limit may be changed from 87 to 85 percent of MMF with no impact on the probability or consequences of an accident previously evaluated. The conclusions of the DCPP Final Safety Analysis Report Update remain valid with this safety analysis limit change. Using the new safety analysis limit, sufficient margin exists between the TS limits and the safety analysis limit to accommodate the channel statistical uncertainty that results from a 30-month operating cycle.

The proposed allowable value change in Table 2.2-1 is in the more restrictive direction and, therefore, does not adversely affect the probability or consequences of accidents.

The increased surveillance interval in Table 4.3-1 does not change the manner in which the plant is operated or the way in which surveillance tests are performed. Evaluation of the specified components indicates they will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

The change in the RCS loss of flow-low safety analysis limit does not create the possibility of a new or different kind of accident since the setpoint will remain as currently specified, the lower safety analysis limit results in an insignificant delay in plant response to the accident, and is bounded by the complete loss of flow accident.

The proposed allowable value change in Table 2.2-1 is more restrictive and, therefore, has no effect on the types of accidents in the facility.

The surveillance history of the RCS flow instruments indicates that the specified components will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

The change in the RCS loss of flow-low safety analysis limit results in an insignificant delay in plant response to credited accidents.

The allowable value change proposed in Table 2.2-1 is more restrictive and, therefore, does not reduce safety margins.

There is no safety analysis impact associated with increasing the surveillance interval for the RCS flow instrumentation. This change will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 8, 36

TECHNICAL SPECIFICATIONS
2.2.1
3/4.3.1

PRESSURIZER LEVEL

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the pressurizer water level allowable value and trip setpoint in TS 2.2.1, Table 2.2-1, and revise the surveillance requirement in TS 3/4.3.1, Table 4.3-1, to change the surveillance frequency from R, at least once per 18 months, to R24, at least once per REFUELING INTERVAL (nominal 24 months, maximum 30 months).

TABLE 7 - PRESSURIZER LEVEL

PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Setpoints (Table 2.2-1)	8	pressurizer water level high	≤92% of instrument span	≤90% of instrument span
Safety Analysis Limits		(no changes proposed)		
Allowable Values (Table 2.2-1)	8	pressurizer water level high	≤92.5%	≤90.2%
Channel Calibration (Table 4.3-1)	36	pressurizer water level high	R	R24

B. BACKGROUND

The pressurizer level protection system uses Rosemount differential pressure transmitters to sense pressurizer level. The transmitter output signals are processed by the Eagle 21 digital processing system. As input to the Westinghouse statistical evaluation of instrumentation calibration accuracy and drift, PG&E compiled as-left/as-found calibration test data. These data were based on the review of completed test procedures, including those executed at refueling outages as well as any midcycle tests that were conducted due to instrument channel problems or modifications. The evaluation of these data was twofold as was done for other

RTS/ESFAS instruments. The evaluation included as-left/as-found data for all of the pressurizer level Rosemount 1153HD5 transmitters in both units over a period of approximately 4 fuel cycles.

C. SAFETY EVALUATION

All data were evaluated for normality and the existence of outliers, which were eliminated where indicated through the use of accepted statistical tests or the identification of mechanistic causes. Of the 44 calibrations from which drift data was possible to be taken, six were eliminated due to mechanistic causes. No statistical outliers were identified or removed.

Five of the six calibrations that were removed were associated with three transmitter failures. All three failures occurred in 1991 or 1992; no transmitter failures have occurred since 1992. The other calibration was removed due to a backfill problem with the transmitter capillary system. In the three cases of transmitter failure, two were detected by operator performance of channel checks. One of the two failures was detected during an outage, following initial calibration, and the other was detected during plant start-up. The third transmitter failure was identified as having potential oil loss problems; however, following transmitter removal, oil loss was not confirmed due to potential radioactive contamination issues.

The remaining drift data set was comprised of approximately 300 data points. The statistical evaluations resulted in a ±5.0 percent span drift allowance for a 30-month calibration interval. The drift uncertainty was used as an input to determine the channel statistical allowance (CSA) using the Westinghouse setpoint methodology. The correlation coefficient of drift with calibration interval was 0.64. This correlation was not significant because the absolute magnitude of the drift decreased with calibration interval such that it was statistically conservative to assume the 18-month based drift was applicable to the 30-month calibration interval.

Along with instrument drift, the determination of all other channel uncertainties, including sensor, rack, M&TE, and process effects for normal environmental conditions, is included in the evaluation. In particular, the process measurement accuracy (PMA) terms have been calculated specifically for DCPP Units 1 and 2. In the past, a generic random value of ±2.0 percent span was used to address the sensitivity of the ΔP transmitter to density changes resulting from adjustments made by the pressurizer pressure control system. As documented in an Instrument Society of America paper (G. E. Lang and J. P. Cunningham, "Delta-P Level Measurement Systems", Instrumentation, Controls, and Automation in the Power Industry, Vol. 34, Proceedings of the Thirty-Fourth Power

Instrumentation Symposium, June 1991), there are several effects which result in measurement errors in ΔP level measurement systems that should be incorporated into the PMA term. Plant-specific values for these effects have been calculated for DCPP Units 1 and 2 based on current operating and calibration conditions. These terms are similar in nature to the PMA terms currently included for the steam generator water level channel, with the exception of fluid velocity, which is not present in the pressurizer. The plant-specific values for the process pressure effect, the containment ambient temperature effect, and the subcooling effect were found to be smaller in absolute magnitude than the previous generic bounding PMA value, but are now considered to be bias terms.

The evaluation of instrument uncertainties is based on the currently installed hardware as defined in the DCPP calibration procedures. Vendor specifications were used as appropriate. The results of the channel statistical calculations for pressurizer level show that the total channel uncertainty was calculated to be 9.12 percent span, which exceeds that which can be supported by the current TS setpoint for the reactor trip function. There is no explicit safety analysis limit identified for this function. However, in order to assure that a steam bubble always exists within the pressurizer for pressurizer pressure control, the total channel uncertainty must be accommodated between the trip setpoint and the top of the span. Therefore, a pressurizer level setpoint change is proposed in order to support an extended surveillance of up to 30 months.

Based on the uncertainty calculations for the pressurizer level channel, PG&E proposes to change the setpoint in the TS (Table 2.2-1, Item 8), and other DCPP documents that address plant setpoints, to reduce the pressurizer level setpoint to less than or equal to 90 percent span. The allowable value is also proposed to be changed to less than or equal to 90.2 percent span (Item 8) to be consistent with the new setpoint.

The projected drift for the installed Rosemount transmitters is the single largest contributor to the channel uncertainties. This value can not be reduced at this time based on as-left/as-found calibration test data, but may be reduced in the future if continued drift trending indicates that actual drift is less than current projected values. Since Rosemount transmitter drift is typically in the range of ±0.6 percent to ±1.2 percent span, it was judged that the ±5 percent span drift is caused by installation and configuration effects associated with the ΔP level measurement system, as well as the transmitter. The pressurizer water level - high instrument has a closed capillary design, which includes a capillary fill feature. The installation and configuration effects have been manifested in recurring surveillance

problems. The problems appeared as calibration zero shifts which are reflected in the statistically determined drift.

The procedures for calibrating these instruments have been revised to improve the repeatability of the surveillance activity. Following procedure revision, the calibration data from the most recent Units 1 and 2 seventh refueling outages show that, except for one transmitter, drift was within the +/-1.2 percent band that would normally be expected for this type of transmitter. As long as the as-found and as-left data reflect both the process effects and transmitter drift, or until more data are available to indicate that transmitter drift is within the more normal +/-1.2 percent band, the ±5 percent span process/transmitter drift allowance will be used to verify continued performance consistent with historical data.

The proposed changes in Table 2.2-1 revise the allowable value and trip setpoint as noted.

Section E of Attachment A provides a safety evaluation applicable to extending the surveillance interval from 18 to 24 months for the pressurizer level instruments. Based on Attachment A and the above evaluation, PG&E has determined that the calibration interval for the pressurizer level instrument can be extended to 30 months to accommodate a 24-month fuel cycle.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed change in Table 2.2-1 revises the allowable value and trip setpoint as noted.

The proposed change to Table 4.3-1 extends the frequency for surveillance from at least once per 18 months, to at least once per refueling interval (i.e., 24 months nominal, 30 months maximum).

The following evaluation is the basis for the no significant hazards consideration determination.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

   The allowable value and trip setpoint changes for pressurizer water level-high in Table 2.2-1 are each in the more restrictive direction. The revised setpoint would tend to trip the reactor sooner than the present settings. These changes ensure that sufficient margin is maintained between the TS limit and the top of the instrument span to

accommodate the channel statistical uncertainty resulting from a 30-month operating cycle.

The increased surveillance interval in Table 4.3-1 does not change the manner in which the plant is operated or the way in which surveillance tests are performed. Evaluation of the specified components indicates they will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

The proposed allowable value and setpoint change in Table 2.2-1 are more restrictive and, therefore, have no effect on the types of accidents in the facility.

The surveillance history of the pressurizer level instruments indicates that the specified components will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

Since normal pressurizer level is maintained at 60 percent span and the no-load Tavg control level is 22 percent span, a change in the setpoint from less than or equal to 92 percent span to less than or equal to 90 percent span is not significant to either plant operation or safety. Since there are no safety analysis limits associated with pressurizer level, the allowable value and setpoint changes proposed in Table 2.2-1 are more restrictive and, therefore, do not reduce safety margins.

There is no safety analysis impact associated with increasing the surveillance interval for the pressurizer level instruments. This

change will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 10, 38, 57, 58, 69, 70

TECHNICAL SPECIFICATIONS
2.2.1
3/4.3.1
3/4.3.2

STEAM GENERATOR LEVEL

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the steam generator (SG) level allowable values in TS 2.2.1, Table 2.2-1, and TS 3/4.3.2, Table 3.3-4, and revise the surveillance requirements in TS 3/4.3.1, Table 4.3-1, and TS 3/4.3.2, Table 4.3-2, to change the surveillance frequency from R, at least once per 18 months, to R24, at least once per REFUELING INTERVAL (nominal 24 months, maximum 30 months).

TABLE 8 - STEAM GENERATOR LEVEL

PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Setpoints		(no changes proposed)		
Safety Analysis Limits		(no changes proposed)		
Allowable Values (Table 2.2-1)	10	SG water level, low-low reactor trip	≥6.8% narrow range instrument span	≥7.0% narrow range instrument span
Allowable Values (Table 3.3-4)	57	turbine trip and feedwater isolation, SG water level, high-high	≤75.5%	≤75.2%
	58	auxiliary feedwater, SG water level low-low	≥6.8%	≥7.0%
Channel Calibration (Table 4.3-1)	38	SG water level low-low reactor trip	R	R24

TABLE 8 - STEAM GENERATOR LEVEL				
PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Channel Calibration (Table 4.3-2)	69	turbine trip and feedwater isolation, SG water level, high-high	R	R24
	70	auxiliary feedwater, SG water level low-low	R	R24

B. BACKGROUND

The SG level protection system uses Rosemount differential pressure transmitters to sense level. The transmitter output signals are processed by the Eagle 21 digital processing system. As input to the Westinghouse statistical evaluation of instrumentation calibration accuracy and drift, PG&E compiled as-left/as-found calibration test data for the SG narrow range level transmitters, which are Rosemount Model 1154DP4RC transmitters. Most of the transmitters have been installed at DCPP since 1988, or earlier. These data were based on a review of completed test procedures, including those executed at refueling outages as well as any midcycle tests that were conducted due to instrument channel problems or modifications. The evaluation of these data was twofold as was done for other RTS/ESFAS instruments.

C. SAFETY EVALUATION

All data were evaluated for normality and the existence of outliers, which were eliminated where indicated through the use of accepted statistical tests or the identification of mechanistic causes. There were approximately 180 calibrations from which drift data were developed. Three calibrations were removed for mechanistic reasons. There were no statistical outliers. There were approximately 1050 drift data points in the final data set. The statistical evaluations resulted in a ±0.9 percent drift allowance for a 30-month calibration interval. The correlation coefficient of drift with calibration interval was insignificant at 0.15. The drift uncertainty was used as an input to determine the channel statistical allowance (CSA) using the Westinghouse setpoint methodology.

Along with instrument drift, the determination of all other channel uncertainties including sensor, rack, M&TE, and process effects for normal environmental conditions was included in the evaluation. In particular, the process measurement accuracy (PMA) terms were calculated specifically for the Model 51 SG configuration currently installed at DCPP Units 1

and 2. While the process pressure effect and the containment ambient temperature effect remained the same as in WCAP-11082, Revision 2, the treatment of the fluid velocity effect and the downcomer subcooling effect was updated. The previous values for these two terms were based on generic evaluations, which provided a bounding magnitude for each term. As documented in an Instrument Society of America paper (G. E. Lang and J. P. Cunningham, "Delta-P Level Measurement Systems," Instrumentation, Controls, and Automation in the Power Industry, Vol. 34, Proceedings of the Thirty-Fourth Power Instrumentation Symposium, June 1991), it has been determined that the fluid velocity effect and the downcomer subcooling effect act as biases in opposite directions. To be conservative, it was decided to only include these effects when their addition would adversely affect the measurement of the setpoint. Thus, the fluid velocity effect is only included for the high-high level actuation and the downcomer subcooling effect is only included for the low-low level trip. In order to consider the magnitude of these two effects, Westinghouse completed studies to determine the absolute maximum values for the fluid velocity effect and the downcomer subcooling effect based on DCPP plant-specific operating conditions and tube plugging levels up to 15 percent. These plant specific values were found to be smaller (in absolute magnitude) than the previous generic bounding values.

The evaluation of instrument uncertainties was based on the currently installed hardware as defined in the DCPP calibration procedures. Vendor specifications were used as appropriate. The total channel uncertainty associated with this channel has been calculated to be 6.93 percent span for the low-low level function and 6.30 percent span for the high-high level function. The margin to the safety analysis limit is 0.25 percent for the low-low level function and 0.70 percent for the high-high level function. Based on the current safety analysis limits and nominal trip setpoints, there are no specific TS setpoint changes or safety analysis limit changes required for the SG level functions.

Because of the change in setpoint methodology, there are proposed changes in the allowable values to greater than or equal to 7.0 percent span in the Table 2.2-1 Item 10 and Table 3.3-4, Item 58, and to less than or equal to 75.2 percent span in the Table 3.3-4, Item 57. The new allowable values are more restrictive than the existing allowable values.

Section E of Attachment A provides a safety evaluation applicable to extending the surveillance interval from 18 to 24 months for the SG level instruments. Based on that evaluation and the evaluation above, PG&E has determined that the channel surveillance interval can be extended for a period up to 30 months consistent with the 24-month fuel cycle.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed changes in Table 2.2-1 and Table 3.3-4 revise the allowable values as noted.

The proposed changes in Tables 4.3-1 and 4.3-2 extend the frequency for surveillances from at least once per 18 months, to at least once per refueling interval (i.e., 24 months nominal, 30 months maximum).

The following evaluation is the basis for the no significant hazards consideration determination.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

   The proposed allowable value changes in Tables 2.2-1 and 3.3-4 are in the more restrictive direction and, therefore, do not adversely affect the probability or consequences of accidents.

   The increased surveillance intervals in Tables 4.3-1 and 4.3-2 do not change the manner in which the plant is operated or the way in which surveillance tests are performed. Evaluation of the specified components indicates they will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

   Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

   The proposed allowable value changes in Tables 2.2-1 and 3.3-4 are more restrictive and, therefore, have no effect on the types of accidents in the facility.

   The surveillance history of the SG level instruments indicates that the specified components will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

The allowable value changes proposed in Tables 2.2-1 and 3.3-4 are more restrictive and, therefore, do not reduce safety margins.

There is no safety analysis impact associated with increasing the surveillance interval for the SG level instruments. This change will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 11, 40, 41, 59, 72

TECHNICAL SPECIFICATIONS
2.2.1
3/4.3.1
3/4.3.2

UNDERVOLTAGE AND UNDERFREQUENCY

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the reactor coolant pump (RCP) undervoltage relay allowable values in TS 2.2.1, Table 2.2-1, and TS 3/4.3.2, Table 3.3-4, and revise the undervoltage relay surveillance requirements in TS 3/4.3.1, Table 4.3-1, and TS 3/4.3.2, Table 4.3-2, to change the surveillance frequency from R, at least once per 18 months, to R24, at least once per REFUELING INTERVAL (nominal 24 months, maximum 30 months). The TS changes would also revise the underfrequency relay surveillance requirements in TS 3/4.3.1, Table 4.3-1, to change the surveillance frequency from at least once per 18 months to at least once per REFUELING INTERVAL (nominal 24 months, maximum 30 months).

TABLE 9 - UNDERVOLTAGE AND UNDERFREQUENCY				
PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Setpoints		(no changes proposed)		
Safety Analysis Limits		(no changes proposed)		
Allowable Values (Table 2.2-1)	11	undervoltage - RCPs	≥7730 volts	≥7877 volts
Allowable Values (Table 3.3-4)	59	auxiliary feedwater, undervoltage- RCP	≥7730 volts	≥7877 volts
Channel Calibration (Table 4.3-1)	40	undervoltage - RCPs	R	R24
	41	underfrequency - RCPs	R	R24

TABLE 9 - UNDERVOLTAGE AND UNDERFREQUENCY				
PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Channel Calibration (Table 4.3-2)	72	auxiliary feedwater, undervoltage - RCP	R	R24
Trip Actuating Device Operational Test (Table 4.3-2)	72	auxiliary feedwater, undervoltage - RCP	R	R24

B. BACKGROUND

The RCP undervoltage and underfrequency relays monitor the 12 kV buses that power the RCPs and provide direct inputs into the reactor trip and engineered safety features actuation systems on the loss or degradation of these buses. Since these channels are not processed by the Eagle 21 system, error sources associated with the racks are not applicable. As input to the Westinghouse statistical evaluation of instrumentation calibration accuracy and drift, PG&E compiled as-left/as-found calibration test data. These data were based on a review of completed test procedures, including those executed at refueling outages as well as any midcycle tests that were conducted due to instrument channel problems, modifications, or quarterly tests.

C. SAFETY EVALUATION

The Westinghouse statistical evaluation of the data was twofold as was done for other RTS/ESFAS instruments. All data were evaluated for normality and the existence of outliers, which were eliminated where indicated through the use of accepted statistical tests or the identification of mechanistic causes.

Undervoltage Relays

During the Units 1 and 2 seventh refueling outages (1R7 and 2R7), the original Westinghouse undervoltage relays were replaced with Basler Model BE1-27 relays; therefore, historical data were not available. The vendor instruction manual for the new Basler relays does not provide a specific drift specification, but discussion with the vendor confirmed that the expected relay drop-out and pick-up setting drift is less than 1.6 volts between calibrations. Therefore, a ±1.6 volt drift allowance was used for 30 months and will be verified to be adequate based on future performance data for the new Basler relays.

Along with instrument drift, the determination of all other channel uncertainties, including potential transformer accuracy, sensor, and M&TE is included in the channel evaluations. The evaluation of instrument uncertainties is based on the currently installed hardware as defined by the DCPP calibration procedures. Vendor specifications were used as appropriate. The basis for determining M&TE uncertainties for this channel is the M&TE currently in use at DCPP for this channel as defined in the calibration procedures.

The total channel uncertainty associated with the RCP undervoltage channel has been calculated to be 2.56 Volts. The safety analyses do not assume an explicit value for the undervoltage setpoint; therefore, a safety analysis limit does not apply. Based on the current safety analysis limits and nominal trip setpoints, there are no TS setpoint changes or safety analysis limit changes required for this trip function.

For the undervoltage function, Item 11, an allowable value change to greater than or equal to 7877 volts to Table 2.2-1 is proposed, which is more restrictive than the existing allowable value and is consistent with WCAP-11082, Revision 5, methodology. The same (7877 volts) new allowable value change is proposed for Item 59 applicable to Table 3.3-4.

During 1R7 and 2R7 the undervoltage relays were replaced with Basler Model BE1-27 relays. Coincident with the relay replacement, the TADOT and the calibration procedure were merged and are currently being performed quarterly. Following replacement of the undervoltage relays, the TADOT has been performed four (4) times on the Unit 1 relays and twice (2) on the Unit 2 relays without any problems. A review of the component history for the previous relays showed that, except for two relays replaced in 1988, there were no problems with the original relays. Therefore, based on the successful performance of the original relays, the successful performance to-date of the TADOTs on the replacement relays and the intention to continue performing the TADOTs quarterly, it is expected that these relays will perform satisfactorily over a 24-month fuel cycle (maximum 30-month calibration interval).

Underfrequency Relays

For the Basler BE1-81 underfrequency relays, which are only calibrated at the trip setpoint, there were 60 drift data points analyzed (three data points identified as statistical outliers were removed, and one data point identified as a mechanical outlier was removed because of a relay failure). The

evaluations resulted in a ±0.04 Hz drift allowance for a 30 month calibration interval.

Along with instrument drift, the determination of all other channel uncertainties, including potential transformer accuracy, sensor, and M&TE is included in the channel evaluations. The evaluation of instrument uncertainties is based on the currently installed hardware as defined by the DCPP calibration procedures. Vendor specifications were used as appropriate. The basis for determining M&TE uncertainties for this channel is the M&TE currently in use at DCPP for this channel as defined in the calibration procedures.

For the RCP underfrequency reactor trip, a total channel uncertainty of 0.091 Hz was calculated. The margin to the safety analysis limit is 0.009 Hz for the underfrequency trip setpoint. Based on the current safety analysis limits and nominal trip setpoints, there are no TS setpoint changes or safety analysis limit changes required for this trip function.

There are no changes in allowable value necessary for the underfrequency parameter.

Summary

Section E of Attachment A provides a safety evaluation applicable to extending the surveillance interval from 18 to 24 months for the undervoltage and underfrequency instruments. Based on that evaluation and the evaluation above, PG&E has determined that the channel surveillance interval can be extended for a period up to 30 months consistent with the 24-month fuel cycle.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed changes in Tables 2.2-1 and 3.3-4 revise the allowable values as noted.

The proposed changes in Tables 4.3-1 and 4.3-2 extend the frequency for surveillances from at least once per 18 months, to at least once per refueling interval (i.e., 24 months nominal, 30 months maximum).

The following evaluation is the basis for the no significant hazards consideration determination.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

The proposed allowable value changes in Tables 2.2-1 and 3.3-4 are all in the more restrictive direction and, therefore, do not adversely affect the probability or consequences of accidents.

The increased surveillance intervals in Tables 4.3-1 and 4.3-2 do not change the manner in which the plant is operated or the way in which surveillance tests are performed. The surveillance and operating history of the specified components indicates they will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

The proposed allowable value changes in Tables 2.2-1 and 3.3-4 are more restrictive and, therefore, have no effect on the possible types of accidents in the facility.

The surveillance history of the undervoltage and underfrequency instruments indicates that the specified components will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

The allowable value changes proposed in Tables 2.2-1 and 3.3-4 are more restrictive and, therefore, do not reduce safety margins.

There is no safety analysis impact associated with increasing the surveillance interval for the undervoltage and underfrequency instruments. These changes will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 14, 18, 43, 47

TECHNICAL SPECIFICATIONS
2.2.1
3/4.3.1

REACTOR TRIP INTERLOCKS/TURBINE IMPULSE PRESSURE

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the turbine impulse pressure input allowable values in TS 2.2.1, Table 2.2-1, and revise the surveillance requirements in TS 3/4.3.1, Table 4.3-1, to change the surveillance frequency from R, at least once per 18 months, to R24, at least once per REFUELING INTERVAL (nominal 24 months, maximum 30 months).

TABLE 10 - REACTOR TRIP INTERLOCKS/TURBINE IMPULSE PRESSURE

PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Setpoints		(no changes proposed)		
Safety Analysis Limits		(no changes proposed)		
Allowable Values (Table 2.2-1)	14	low power reactor trips block, P-7, P-13 input	≤12.1% RTP turbine impulse pressure equivalent	≤10.2% RTP turbine impulse pressure equivalent
	18	turbine impulse chamber pressure, P-13	≤12.1%	≤10.2%
Channel Calibration (Table 4.3-1)	43	low power reactor trips block, P-7	R	R24
	47	turbine impulse chamber pressure, P-13	R	R24
Channel Operational Test (Table 4.3-1)	43	low power reactor trips block, P-7	R	R24

TABLE 10 - REACTOR TRIP INTERLOCKS/TURBINE IMPULSE PRESSURE				
PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
	47	turbine impulse chamber pressure, P-13	R	R24

B. BACKGROUND

The turbine impulse pressure interlock instrumentation consists of two pressure transmitters in each unit whose output signals are processed by the Eagle 21 digital processing system. One Unit 1 transmitter is a Rosemount 1153GD8RC and the other is a Barton 763. Both of the Unit 2 transmitters are Rosemount Model 1153GD8RC. As input to the Westinghouse statistical evaluation of instrumentation calibration accuracy and drift, PG&E compiled as-left/as-found calibration test data for the transmitters. These data were based on a review of completed test procedures, including those executed at refueling outages as well as any midcycle tests that were conducted due to instrument channel problems, modifications, or quarterly tests.

Item 43 was previously discussed in the power range neutron flux section above, and is included in this section as well since one of its inputs is the P-13 interlock from turbine impulse pressure.

C. SAFETY EVALUATION

The difference between as-found and as-left data for the transmitters was used to statistically calculate projected drift for a 30-month calibration interval at a 95 percent probability and a 95 percent confidence level, including an assessment of drift time dependence. All data were evaluated for normality and the existence of outliers, which were eliminated where indicated through the use of accepted statistical tests or the identification of mechanistic causes.

There were approximately 170 drift data points included in the Barton pressure transmitter analysis (only one data point was eliminated for a mechanistic cause). The statistical evaluation resulted in a -0.2 percent bias, ± 1.2 percent span random drift allowance for the Barton 763 transmitters for a 30-month calibration interval. The bias represents a nonconservative direction for the reactor trip system interlock function; therefore, this bias uncertainty was incorporated in the uncertainty calculation.

There were insufficient data available to determine a statistical drift for the Rosemount transmitters. Therefore, a drift of ± 1.2 percent span was assumed for the Rosemount transmitters based on the drift analysis results for the same model Rosemount transmitters used in other applications at DCPP (e.g., RCS flow and feedwater flow transmitters, which are also Model 1153 transmitters). The Rosemount vendor specifications indicate that a drift allowance of 0.3 percent span for 30 months is appropriate; however, experience indicates that this number is too small. The assumed drift allowance is greater than 3 times the vendor-specified amount, which adds conservatism. This allowance will be validated by future monitoring.

This drift allowance was used as an input to determine the channel statistical allowance (CSA) using the Westinghouse setpoint methodology. The evaluation of instrument uncertainties is based on the currently installed hardware as defined by DCPP calibration procedures. Vendor specifications were used as appropriate.

A total channel uncertainty of 2.19 percent span for the P-13 Interlock function was calculated for the Rosemount transmitters, which reflects a 30-month surveillance period. For the channel with the Barton transmitter, an uncertainty of 2.57 percent span was calculated, which also reflects a 30-month surveillance interval.

The safety analyses do not explicitly credit the P-13 interlock; thus, a safety analysis limit does not apply to these channels. There are no TS setpoint changes or safety analysis limit changes required for this interlock. Because of the change in setpoint methodology, there are proposed changes in the allowable value to less than or equal to 10.2 percent rated thermal power turbine impulse pressure equivalent in the Table 2.2-1, Items 14 and 18. The new allowable values are more restrictive than the existing allowable values and were determined consistent with the WCAP-11082, Revision 5, methodology.

Section E of Attachment A provides a safety evaluation applicable to extending the surveillance interval from 18 to 24 months for the turbine impulse pressure instruments. Based on that evaluation and the evaluation above, PG&E has determined that the channel surveillance interval can be extended for a period up to 30 months consistent with the 24-month fuel cycle.

All of the turbine impulse pressure transmitters have been installed for at least the last two fuel cycles and have successfully passed post-installation calibrations. A review of the Plant Information Management System component history for the electronic (Eagle 21) portion of these channels

did not identify any problems with the calibrations or the quarterly COTs performed since the installation of Eagle 21 (during the Units 1 and 2 fifth refueling outages). Based on the performance of the transmitters since installation, and the successful performance of the COTs for the post-Eagle 21 configuration, it is proposed that the frequency for this COT be extended to R24.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed changes in Table 2.2-1 revise the allowable values as noted.

The proposed changes in Tables 4.3-1 extend the frequency for surveillances from at least once per 18 months, to at least once per refueling interval (i.e., 24 months nominal, 30 months maximum).

The following evaluation is the basis for the no significant hazards consideration determination.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

   The proposed allowable value changes in Table 2.2-1 are in the more restrictive direction and, therefore, do not adversely affect the probability or consequences of accidents.

   The increased surveillance intervals in Table 4.3-1 do not change the manner in which the plant is operated or the way in which surveillances are performed. The surveillance and operating history of the specified components indicates they will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

   Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

   The allowable value changes proposed in Table 2.2-1 are more restrictive and, therefore, have no effect on the possible types of accidents in the facility.

The surveillance history of the turbine impulse pressure instruments indicates that the specified components will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

The allowable value changes proposed in Table 2.2-1 are more restrictive and, therefore, do not reduce safety margins.

There is no safety analysis impact associated with increasing the surveillance interval for the turbine impulse pressure instruments. These changes will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 49, 52, 53, 54, 61, 64, 65, 66

TECHNICAL SPECIFICATION 3/4.3.2

CONTAINMENT PRESSURE

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the containment pressure allowable values in TS 3/4.3.2, Table 3.3-4, and revise the surveillance requirements in TS 3/4.3.2, Table 4.3-2, to change the surveillance frequency from R, at least once per 18 months, to R24, at least once per REFUELING INTERVAL (nominal 24 months, maximum 30 months).

TABLE 11 - CONTAINMENT PRESSURE

PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Setpoints		(no changes proposed)		
Safety Analysis Limits		(no changes proposed)		
Allowable Values (Table 3.3-4)	49	safety injection, containment pressure high	≤3.3 psig	≤3.12 psig
	52	containment spray, containment pressure high-high	≤22.3 psig	≤22.12 psig
	53	phase B isolation, containment pressure high-high	≤22.3 psig	≤22.12 psig
	54	steam line isolation, containment pressure high-high	≤22.3 psig	≤22.12 psig
Channel Calibration (Table 4.3-2)	61	safety injection, containment pressure high	R	R24
	64	containment spray, containment pressure high-high	R	R24
	65	phase B isolation, containment pressure high-high	R	R24

TABLE 11 - CONTAINMENT PRESSURE				
PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
	66	steam line isolation, containment pressure high-high	R	R24

B. BACKGROUND

The containment pressure protection system uses Rosemount differential pressure transmitters to sense containment pressure. The transmitter output signals are processed by the Eagle 21 digital processing system. Rosemount Model 1154DP6 transmitters were recently installed in the containment pressure channels. Because these transmitters were recently installed, there are insufficient data available to determine a statistical drift value.

C. SAFETY EVALUATION

Since there were insufficient data for statistical analysis, vendor specifications and the performance of the transmitters in other applications was considered. Rosemount specifications would indicate that a drift allowance of 0.3 percent span for 30 months is appropriate; however, experience indicates that this number is too small. Therefore, a review was performed of Rosemount drift results for the other DCPP functions (e.g., RCS flow, narrow range steam generator level, and feedwater flow), as well as for the other plants' 24-month fuel cycle programs performed by Westinghouse. It was Westinghouse's and PG&E's engineering judgment, supported by this review, that a drift value of ±1.2 percent span is conservative for these transmitters. This allowance will be validated by future monitoring.

Along with instrument drift, the determination of all other channel uncertainties including sensor, rack, and M&TE was included in the evaluation. The evaluation of instrument uncertainties is based on the currently installed hardware as defined in the DCPP calibration procedures. Vendor specifications were used as appropriate. The total channel uncertainty associated with this channel has been calculated to be 2.20 percent span for both the high and the high-high trip functions. The margin to the safety analysis limit is 1.13 percent for the high function and 2.30 percent for the high-high function. Based on the current safety analysis limits and nominal trip setpoints, there are no TS setpoint changes or safety analysis limit changes required for the containment pressure high and high-high engineered safety features functions.

Because of the change in setpoint methodology of WCAP-11082, Revision 5, there are proposed changes to allowable values (see Table 11). The new allowable values are more restrictive than the existing allowable values.

A review of the Plant Information Management System component history for the electronic (Eagle 21) portion of these channels did not identify any problems with the calibrations or the quarterly channel operational tests (COTs) performed since the installation of Eagle 21 (in the Units 1 and 2 fifth refueling outages). Based on conservative assumptions of Rosemount transmitter drift and the successful performance of the COTs for the post-Eagle 21 configuration, it is expected that these channels will perform satisfactorily over a 24-month fuel cycle (maximum 30-month calibration interval).

Section E of Attachment A provides a safety evaluation applicable to extending the surveillance interval from 18 to 24 months for the containment pressure instruments. Based on that evaluation and the evaluation above, PG&E has determined that the channel surveillance intervals can be extended for a period up to 30 months consistent with the 24-month fuel cycle.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed changes in Tables 3.3-4 revise the allowable values as noted.

The proposed changes in Tables 4.3-2 extend the frequency for surveillances from at least once per 18 months, to at least once per refueling interval (i.e., 24 months nominal, 30 months maximum).

The following evaluation is the basis for the no significant hazards consideration determination.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

   The proposed allowable value changes in Table 3.3-4 are all in the more restrictive direction and, therefore, do not adversely affect the probability or consequences of accidents.

   The increased surveillance intervals in Table 4.3-2 do not change the manner in which the plant is operated or the way in which surveillance

tests are performed. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

The proposed allowable value changes in Table 3.3-4 are more restrictive and, therefore, have no effect on the possibility types of accidents in the facility.

The surveillance history of the containment pressure instruments indicates that the specified components will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

The proposed allowable value changes in Table 3.3-4 are more restrictive and, therefore, do not reduce safety margins.

There is no safety analysis impact associated with increasing the surveillance interval for the containment pressure instruments. These changes will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 51, 55, 56, 63, 67, 68

TECHNICAL SPECIFICATION 3/4.3.2

STEAM LINE PRESSURE

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the steam line pressure allowable values in TS 3/4.3.2, Table 3.3-4, and revise the surveillance requirements in TS 3/4.3.2, Table 4.3-2, to change the surveillance frequency from R, at least once per 18 months, to R24, at least once per REFUELING INTERVAL (nominal 24 months, maximum 30 months).

TABLE 12 - STEAM LINE PRESSURE

PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Setpoints		(no changes proposed)		
Safety Analysis Limits		(no changes proposed)		
Allowable Values (Table 3.3-4)	51	safety injection, steam line pressure - low	≥594.6 psig	≥597.6 psig
	55	steam line isolation, steam line pressure - low	≥594.6 psig	≥597.6 psig
	56	steam line isolation, negative steam line pressure rate - high	≤105.4 psi	≤102.4 psi
Channel Calibration (Table 4.3-2)	63	safety injection, steam line pressure - low	R	R24
	67	steam line isolation, steam line pressure - low	R	R24
	68	steam line isolation, negative steam line pressure rate - high	R	R24

B. BACKGROUND

The steam line pressure protection system uses Rosemount and Barton pressure transmitters to sense pressure. The transmitter output signals are processed by the Eagle 21 digital processing system. As input to the Westinghouse statistical evaluation of instrumentation calibration accuracy and drift, PG&E compiled as-left/as-found calibration test data for both the Barton and Rosemount pressure transmitters. The evaluation included as-left/as-found data for all of the steam pressure Barton Model 763 transmitters in both units over a period of approximately 4 cycles. Currently, 21 of the 24 steam generator pressure transmitters are Barton Model 763 transmitters, and the remaining three are Rosemount Model 1154SH9RC transmitters. These data were based on a review of completed test procedures, including those executed at refueling outages, as well as any midcycle tests that were conducted due to instrument channel problems or modifications. The evaluation of these data was twofold as was done for other RTS/ESFAS instrumentation.

C. SAFETY EVALUATION

The Barton transmitter data were evaluated for normality and for the existence of outliers, which were eliminated where indicated through the use of accepted statistical tests or the identification of mechanistic causes. There were approximately 1700 drift data points which remained in the data set after the removal of three calibration data sets based on statistical outlier tests. The statistical evaluations resulted in a ±1.2 percent span random drift allowance with a -0.2 percent bias for a 30-month calibration interval. The drift magnitude correlation coefficient with calibration interval was 0.24, which is not significant. The random drift uncertainty was used as an input to determine the channel statistical allowance (CSA) using the Westinghouse setpoint methodology. Since the -0.2 percent bias is in the more conservative direction for the steam line pressure ESF functions, it was not included in the CSA determination.

Rosemount Model 1154SH9RC transmitters are installed in three of the steam pressure channels. Because these transmitters were recently installed, there are insufficient data available to determine a statistical drift value. Therefore, a review of Rosemount drift results for other DCPP functions (i.e., RCS flow and feedwater flow), as well as for other 24-month fuel cycle programs was performed. It was Westinghouse's and PG&E's engineering judgment, supported by this review, that the drift value of ±1.2 percent span calculated for the Barton 763 transmitters is also appropriate for the Rosemount transmitters. This value is 2.4 times larger

than the vendor's specified 30-month drift of 0.50 percent span for this application. This allowance will be validated by future monitoring.

The evaluation of instrument uncertainties is based on the currently installed hardware as defined by PG&E in the calibration procedures. Vendor specifications were used as appropriate. Along with instrument drift, the determination of all other channel uncertainties including sensor, rack, M&TE, and process effects for normal environmental conditions was included in the evaluation.

The total channel uncertainty associated with this channel is calculated to be 8.34 percent span for the Barton transmitters and 8.03 percent span for the Rosemount transmitters. The margin to the safety analysis limit is 4.68 percent span for the Barton transmitters and 4.99 percent span for the Rosemount transmitters. Based on the current safety analysis limits and nominal trip setpoints, there are no specific TS setpoint changes or safety analysis limit changes required for the steam line pressure ESF functions.

Because of the change in setpoint methodology consistent with WCAP-11082, Revision 5, there are proposed changes to allowable values (see Table 12). The new allowable values are more restrictive than the existing allowable values.

A review of the Plant Information Management System component history for the electronic (Eagle 21) portion of these channels did not identify any problems with the calibrations or the quarterly COTs performed since the installation of Eagle 21 (in the Units 1 and 2 fifth refueling outages). Based on the conservative assumptions for Rosemount transmitter drift and the successful performance of the COTs for the post-Eagle 21 configuration, it is expected that these channels will perform satisfactorily over a 24-month fuel cycle (maximum 30-month calibration interval).

Section E of Attachment A provides a safety evaluation applicable to extending the surveillance interval from 18 to 24 months for the steam line pressure instruments. Based on that evaluation and the evaluation above, PG&E has determined that the channel surveillance interval can be extended for a period up to 30 months consistent with the 24-month fuel cycle.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed changes in Table 3.3-4 revise the allowable values as noted.

The proposed changes in Table 4.3-2 extend the frequency for surveillances from at least once per 18 months, to at least once per refueling interval (i.e., 24 months nominal, 30 months maximum).

The following evaluation is the basis for the no significant hazards consideration determination.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

   The proposed allowable value changes in Table 3.3-4 are all in the more restrictive direction and, therefore, do not adversely affect the probability or consequences of accidents.

   The increased surveillance intervals in Table 4.3-2 do not change the manner in which the plant is operated or the way in which surveillance tests are performed. The surveillance and operating history of the Barton transmitters indicates they will continue to perform satisfactorily with a longer surveillance interval. While the subject Rosemount transmitters do not have sufficient operating history in this specific application, similar Rosemount transmitters used elsewhere at DCPP indicate that these transmitters will continue to perform satisfactorily as well with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

   Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

   The proposed allowable value changes in Table 3.3-4 are more restrictive and, therefore, have no effect on the possible types of accidents in the facility.

   The surveillance history of the steam line pressure instruments indicates that the specified components will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

The proposed allowable value changes in Table 3.3-4 are more restrictive and, therefore, do not reduce safety margins.

There is no safety analysis impact associated with increasing the surveillance interval for the steam line pressure instruments. These changes will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 6, 7, 34, 35, 50, 60, 62, 73

TECHNICAL SPECIFICATIONS
2.2.1
3/4.3.1
3/4.3.2

PRESSURIZER PRESSURE

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the pressurizer pressure allowable values in TS 2.2.1, Table 2.2-1, and TS 3/4.3.2, Table 3.3-4, and revise the surveillance requirements in TS 3/4.3.1, Table 4.3-1, and TS 3/4.3.2, Table 4.3-2, to change the surveillance frequency from R, at least once per 18 months, to R24, at least once per REFUELING INTERVAL (nominal 24 months, maximum 30 months).

TABLE 13 - PRESSURIZER PRESSURE

PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Setpoints		(no changes proposed)		
Safety Analysis Limits		(no changes proposed)		
Allowable Values (Table 2.2-1)	6	pressurizer pressure, low	≥1944.4 psig	≥1947.5 psig
	7	pressurizer pressure, high	≤2390.6 psig	≤2387.5 psig
Allowable Values (Table 3.3-4)	50	safety injection , pressurizer pressure - low	≥1844.4 psig	≥1847.5 psig
	60	ESFAS interlocks, pressurizer pressure, P-11	≤1920.6 psig	≤1917.5 psig
Channel Calibration (Table 4.3-1)	34	pressurizer pressure low	R	R24
	35	pressurizer pressure, high	R	R24
Channel Calibration (Table 4.3-2)	62	safety injection, pressurizer pressure - low	R	R24

TABLE 13 - PRESSURIZER PRESSURE				
PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
	73	ESFAS interlocks, pressurizer pressure, P-11	R	R24

B. BACKGROUND

The pressurizer pressure protection system uses Rosemount pressure transmitters to sense pressurizer pressure. Rosemount Model 1154SH9 transmitters were recently installed in the pressurizer pressure channels; therefore, there are insufficient data available to determine a statistical drift value. The transmitter output signals are processed by the Eagle 21 digital processing system. The system was reviewed using the Westinghouse methodology for evaluating channel uncertainties. Each uncertainty term was determined according to the instrument characteristics/specifications.

C. SAFETY EVALUATION

Since there were insufficient calibration data to support a statistical analysis of drift, vendor specifications and the performance of the transmitters in other applications was considered. Rosemount specifications indicate that a drift allowance of 0.48 percent span for 30 months would be appropriate; however, experience indicates that this number is smaller than actually experienced at DCPP. Therefore, a review was performed of Rosemount drift results for other DCPP functions (i.e., RCS flow, narrow range steam generator level, and feedwater flow), as well as for other plants' 24-month fuel cycle programs performed by Westinghouse. It was Westinghouse and PG&E's engineering judgment, supported by this review, that a drift value of ±1.2 percent span is conservative for these transmitters. This allowance shall be validated by the DCPP Drift Monitoring Program

The ±1.2 percent span drift allowance was used as an input to determine the channel statistical allowance (CSA) using the Westinghouse setpoint methodology. Along with instrument drift, the determination of all other channel uncertainties including sensor, rack, M&TE, and process effects for normal environmental conditions is included in the evaluation. The evaluation of instrument uncertainties is based on the currently installed hardware as defined by the DCPP calibration procedures. Vendor specifications were used as appropriate.

The total channel uncertainty associated with this channel has been calculated to be 2.30 percent span for the low pressure reactor trip

function, 2.30 percent span for the high pressure reactor trip function, and 9.18 percent span for the low pressure safety injection (SI) function. The margin to the safety analysis limit is 6.10 percent span for the low pressure reactor trip, 2.50 percent span for the high pressure reactor trip and 4.40 percent span for the low pressure SI function. Based on the current safety analysis limits and nominal trip setpoints, there are no TS setpoint changes or safety analysis limit changes required for the pressurizer pressure functions.

Because of the change in setpoint methodology consistent with WCAP-11082, Revision 5, there are proposed changes to allowable values (see Table 13). The new allowable values are more restrictive than the existing allowable values.

A review of the Plant Information Management System component history for the electronic (Eagle 21) portion of these channels did not identify any problems with the calibrations or the quarterly COTs performed since the installation of Eagle 21 (in the Units 1 and 2 fifth refueling outages). Based on the conservative assumption of Rosemount transmitter drift and the successful performance of the COTs for the post-Eagle 21 configuration, it is expected that these channels will perform satisfactorily over a 24-month fuel cycle (maximum 30-month calibration interval).

Section E of Attachment A provides a safety evaluation applicable to extending the surveillance interval from 18 to 24 months for the pressurizer pressure instruments. Based on that evaluation and the evaluation above, PG&E has determined that the channel surveillance intervals can be extended for a period up to 30 months consistent with the 24-month fuel cycle.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed changes in Tables 2.2-1 and 3.3-4 revise the allowable values as noted.

The proposed changes in Tables 4.3-1 and 4.3-2 extend the frequency for surveillances from at least once per 18 months, to at least once per refueling interval (i.e., 24 months nominal, 30 months maximum).

The following evaluation is the basis for the no significant hazards consideration determination.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

The proposed allowable value changes in Tables 2.2-1 and 3.3-4 are in the more restrictive direction and, therefore, do not adversely affect the probability or consequences of accidents.

The increased surveillance intervals in Tables 4.3-1 and 4.3-2 do not change the manner in which the plant is operated or the way in which surveillance tests are performed. While the subject Rosemount transmitters do not have sufficient operating history in this specific application, similar Rosemount transmitters used elsewhere at DCPP indicate that these transmitters will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

The allowable value changes proposed in Tables 2.2-1 and 3.3-4 are more restrictive and, therefore, have no effect on the possible types of accidents in the facility.

The surveillance history of the pressurizer pressure instruments indicates that the specified components will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

The allowable value changes proposed in Tables 2.2-1 and 3.3-4 are more restrictive and, therefore, do not reduce safety margins.

There is no safety analysis impact associated with increasing the surveillance interval for the pressurizer pressure instruments. These changes will have no effect on any safety limit, protection system

setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 19, 48

TECHNICAL SPECIFICATIONS
2.2.1
3/4.3.1

SEISMIC TRIP

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the seismic trip allowable value in TS 2.2.1, Table 2.2-1, and revise the surveillance requirements in TS 3/4.3.1, Table 4.3-1, to change the surveillance frequency from R, at least once per 18 months, to R24, at least once per REFUELING INTERVAL (nominal 24 months, maximum 30 months). Additionally, the actuation logic test would be revised from at least once per 18 months to a staggered monthly frequency to correspond with other RTS functions.

TABLE 14 - SEISMIC TRIP

PARAMETER	ITEM NO.	DESCRIPTION	CURRENT	NEW
Setpoints		(no changes proposed)		
Safety Analysis Limits		(no changes proposed)		
Allowable Values (Table 2.2-1)	19	seismic trip	≤0.40 g	≤0.43 g
Calibration Frequency (Table 4.3-1)	48	seismic trip	R	R24
Trip Actuating Device Operational Test (Table 4.3-1)	48	seismic trip	R	R24
Actuation Logic Test (Table 4.3-1)	48	seismic trip	R	M(7)

B. BACKGROUND

Operation of the seismic trip system is not required or assumed to mitigate the consequences of any accident analyzed in Chapter 15 of the FSAR Update. DCPP was licensed on the basis of its capability to safely shut down following either the Hosgri or double-design earthquake without relying on the seismic trip system.

The seismic trip function surveillance requirements were revised to their current format in License Amendments 48 (Unit 1) and 47 (Unit 2), issued February 6, 1990. At that time, DCPP was in the midst of modifying the circuits from a relay actuation scheme in the reactor trip breaker control circuits to a solid state protection system (SSPS) actuation scheme similar to that of other RTS functions. The TS which were issued allowed operation under either scheme. In 1990, DCPP completed modifying both units to operate through the SSPS.

DCPP has been testing the seismic trip actuation logic on a staggered monthly basis ever since each unit was modified to operate through the SSPS. On the staggered monthly test schedule, one train of SSPS actuation logic is tested each month, so each train is tested every 62 days. During the test, simulated input signals are provided in every possible combination to the logic section and the required logic output is verified.

As input to the Westinghouse statistical evaluation of instrumentation calibration accuracy and drift, PG&E compiled as-left/as-found calibration test data for the seismic triggers. These data were based on a review of completed test procedures, including those executed at refueling outages as well as any midcycle tests that were conducted due to instrument channel problems, modifications, or quarterly tests. The evaluation of these data was twofold as was done for other RTS/ESFAS instruments.

C. SAFETY EVALUATION

Drift

All seismic trip channel data were evaluated for normality and the existence of outliers, which were eliminated where indicated through the use of accepted statistical tests or the identification of mechanistic causes. There were approximately 100 drift data points in the analyzed data set after three data points were removed for mechanistic causes. There were no statistical outliers removed from the data set. The statistical evaluations resulted in a ±0.086 g random and -0.0042 g bias drift allowance for a 30-month calibration interval for the seismic relays. It should be noted that

a negative bias means that the seismic trip unit actuates at a lower value than desired, which is conservative for a high (increasing) trip function. Therefore, this bias is not included in the uncertainty calculations. The seismic trigger drift correlation coefficient with time was 0.13, which is insignificant.

Along with instrument drift, the determination of all other channel uncertainties including sensor and M&TE was included in the evaluation. The seismic switches are self-contained and, thus, there are no rack components to include in the uncertainty calculation. The evaluation of instrument uncertainties is based on the currently installed hardware as defined in the DCPP calibration procedures. Vendor specifications were used as appropriate. The basis for determining M&TE uncertainties for this channel is the M&TE currently in use at the plant for this channel as defined in the calibration procedures. The seismic trigger manufacturer, who supplied both the sensor and the M&TE, provided an overall accuracy value for the combination of the sensor and its calibrator; therefore, the M&TE has been set to zero in the calculations.

The total channel uncertainty associated with the seismic trip channels has been calculated to be 0.11 g. There is no safety analysis limit for these channels. However, there are design limits based on the Hosgri re-verification of DCPP integrity following a postulated seismic event, with horizontal ground level accelerations of ≤0.75 g and vertical ground accelerations of ≤0.5 g. Based on these limits and a TS trip setpoint of 0.35 g, there is 0.04 g margin to the vertical design limit and 0.29 g to the horizontal design limit. Therefore, there are no specific TS setpoint, safety analysis limit, or design limit changes required for the seismic trip function.

The addition of the statistically based drift and sensor M&TE to the trip setpoint gives a new allowable value for Functional Unit 23 (Item 19) in Table 2.2-1. The new allowable value is less than or equal to 0.43 g. This allowable value is greater than the previous value but is consistent with the methodology of WCAP-11082, Revision 5, and the guidance in GL 91-04. Since Functional Unit 23 does not have a safety analysis limit, there is no safety consequence to this increased allowable value and, as stated previously, the seismic design limits are met. The statistical drift value is significant for the monitoring of the operability of the equipment. There were a small proportion of mechanistic failures in the drift data (again, approximately 100 drift data points were in the analyzed data set after three data points were removed for mechanistic causes, and there were no statistical outliers removed from the data set). These data, with high confidence and high probability, represents the expected future

performance of this equipment. Therefore, PG&E proposes to change the allowable value to less than or equal to 0.43 g.

Section E of Attachment A provides a safety evaluation applicable to extending the surveillance interval from 18 to 24 months for the seismic trip instruments. Based on that evaluation and the evaluation above, PG&E has determined that the channel surveillance interval can be extended for a period up to 30 months consistent with the 24 month fuel cycle.

Trip Actuating Device Operational Test (TADOT)

Since the TADOT is the same as the channel calibration for this function, a review of the Plant Information Management System component history for the seismic triggers was performed. The review did not identify any problems with the testing and performance of the seismic triggers that was not already reflected in the statistical drift analysis performed on the calibration data. Therefore, it is proposed that the frequency for this TADOT be extended to R24.

Actuation Logic Testing

The proposed change in the actuation logic test frequency from refueling to staggered monthly testing provides a more stringent requirement than previously required. This modification is being imposed to be consistent with other RTS actuation logic test requirements in the DCPP TS. DCPP already tests the seismic trip function on this basis, at the same time all other train related actuation logic testing is performed. This change does not impact the safety analysis or the performance of the SSPS or seismic trip channels.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed change in Table 2.2-1 revises the allowable value as noted.

The proposed changes in Table 4.3-1 extends the frequency for channel calibration and TADOT surveillance from at least once per 18 months, to at least once per refueling interval (i.e., 24 months nominal, 30 months maximum), and revises the frequency for the actuation logic test surveillance from at least once per 18 months to at least once per 31 days on a staggered test basis.

The following evaluation is the basis for the no significant hazards consideration determination.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

   Operation of the seismic trip system is not required or assumed to mitigate the consequences of any accident in the FSAR Update safety analyses.

   The proposed allowable value change in Table 2.2-1 does not exceed the design limits based on the Hosgri reverification of DCPP integrity following a postulated seismic event. Margin is maintained to both the horizontal and vertical ground level accelerations. Therefore, this allowable value change does not adversely affect the probability or consequences of accidents.

   The increased surveillance interval does not change the manner in which the plant is operated or the way in which surveillance tests are performed. The surveillance and operating history of the specified components indicates they will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

   The decreased surveillance interval for the actuation logic test provides a more stringent requirement. This requirement does not adversely affect the probability or consequences of accidents. The more stringent requirement is imposed to be consistent with other RTS actuation logic test requirements in the DCPP TS.

   Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

   The proposed allowable value change in Table 2.2-1 does not exceed the design limits based on the Hosgri reverification of DCPP integrity following a postulated seismic event. Margin is maintained to both the horizontal and vertical ground level accelerations. Therefore, the allowable value change has no effect on the possible types of accidents in the facility.

   The surveillance history of the seismic trip instruments indicates that the specified components will continue to effectively perform their design function for longer operating cycles. Additionally, the

increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

The decreased surveillance interval for the actuation logic test provides a more stringent requirement. The decreased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

Since the seismic trip system is not assumed to function for any of the Chapter 15 FSAR Update accident analyses, there is no effect on the margin of safety as defined in those analyses.

There is no safety analysis impact associated with increasing the surveillance interval for the seismic trip instruments. The decreased surveillance interval for the actuation logic test provides a more stringent requirement. These changes will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

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TECHNICAL SPECIFICATION
BASES 2.2.1
REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

TECHNICAL SPECIFICATION
BASES 3/4.3.1 and 3/4.3.2
REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

A. DESCRIPTION OF CHANGE

This TS change would revise the Bases Section for TS 2.2.1 to support the changes made in Table 2.2-1. The proposed Bases changes include additions to better describe calibration tolerance and rack drift, as well as several clarifications and terminology changes.

This TS change also would revise the Bases Section for TS 3/4.3.1 and 3/4.3.2 to include clarification to support the changes made in those TS.

Both Bases Section changes provide additional information on administrative redefinition of TS trip setpoints. Redefinition has always been available in the conservative direction. These Bases Section changes clarify acceptable plant operation.

B. BACKGROUND

PG&E has developed the proposed changes to Bases 2.2.1 to provide improved support for the setpoint information in TS Table 2.2-1. PG&E has developed the proposed changes to the Bases for TS 3/4.3.1 and 3/4.3.2 to provide improved support for those TS as well.

C. SAFETY EVALUATION

The proposed changes to the Bases are administrative in nature and have no effect on plant safety.

D. NO SIGNIFICANT HAZARDS EVALUATION

The following evaluation is the basis for the no significant hazards consideration determination.

1. *Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?*

   The proposed changes to the Bases sections are administrative changes that have no effect on the probability or consequences of an accident.

   Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?*

   The proposed changes to the Bases sections are administrative changes that do not affect potential accidents.

   Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. *Does the change involve a significant reduction in a margin of safety?*

   The proposed changes to the Bases sections are administrative changes that do not affect plant safety.

   Therefore, the proposed changes do not involve a significant reduction in a margin of safety.