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2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

REACTOR CORE

2.1.1 The combination of the reactor coolant core outlet pressure and outlet temperature shall not exceed the safety limit shown in Figure 2.1-1.

APPLICABILITY: MODES 1 and 2.

ACTION:

Whenever the point defined by the combination of reactor coolant core outlet pressure and outlet temperature has exceeded the safety limit, be in HOT STANDBY within one hour.

REACTOR CORE

2.1.2 The combination of reactor THERMAL POWER and AXIAL POWER IMBALANCE shall not exceed the protective limit shown in the CORE OPERATING LIMITS REPORT for the various combinations of three and four reactor coolant pump operation.

APPLICABILITY: MODE 1.

ACTION:

Whenever the point defined by the combination of Reactor Coolant System flow, AXIAL POWER IMBALANCE and THERMAL POWER has exceeded the appropriate protective limit, be in HOT STANDBY within one hour, and comply with the requirements of Specification 6.7.2.

REACTOR COOLANT SYSTEM PRESSURE

2.1.3 The Reactor Coolant System pressure shall not exceed 2750 psig.

APPLICABILITY: MODES 1, 2, 3, 4 and 5.

ACTION:

MODES 1 and 2 -	Whenever the Reactor Coolant System pressure has exceeded 2750 psig, be in HOT STANDBY with the Reactor Coolant System pressure within its limit within one hour.
MODES 3, 4 and 5 -	Whenever the Reactor Coolant System pressure has exceeded 2750 psig, reduce the Reactor Coolant System pressure to within its limit within 5 minutes.

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Figure 2.1-1 Reactor Core Safety Limit

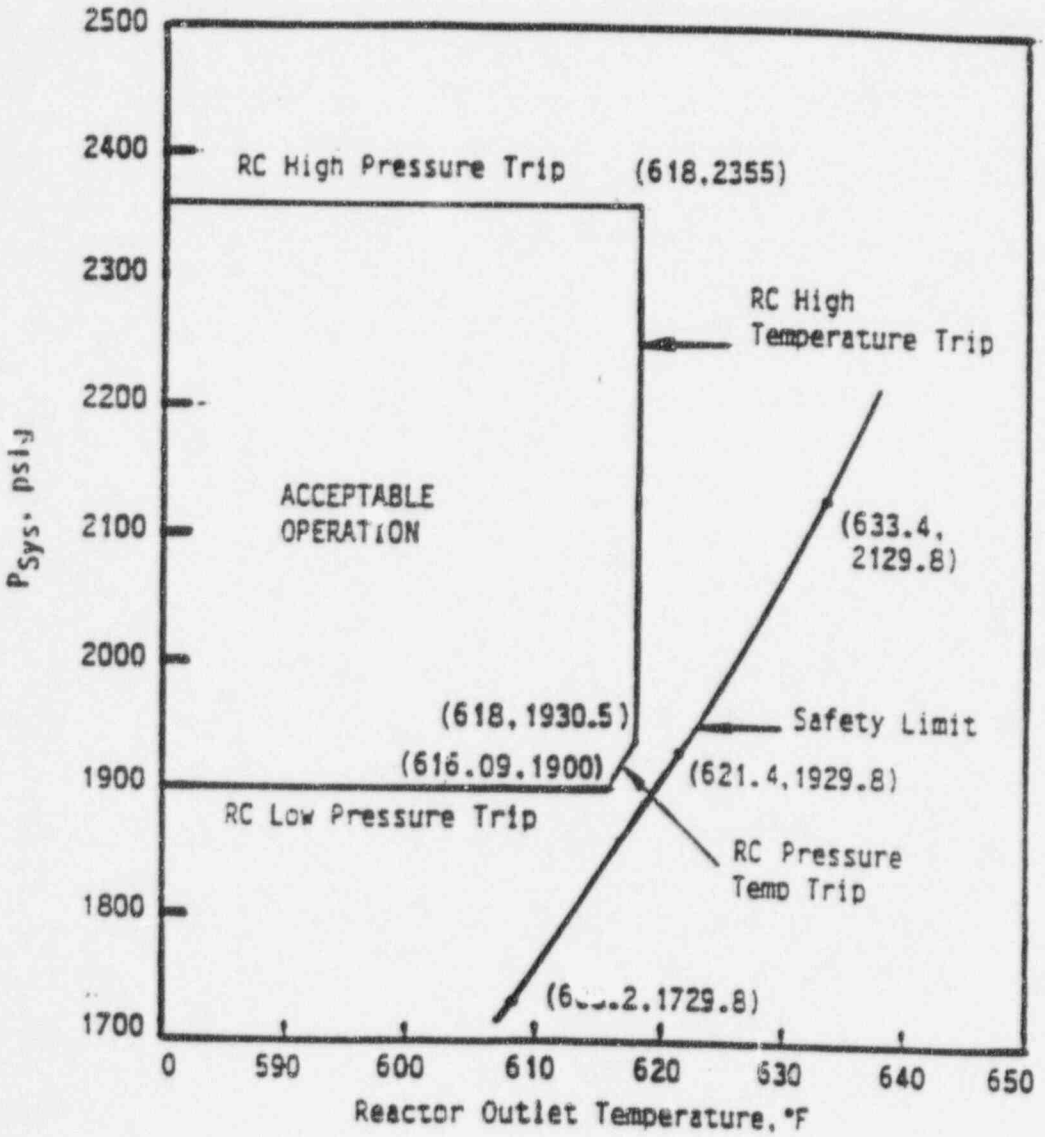

Figure 2.1-2 Reactor Core Safety Limit

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2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR PROTECTION SYSTEM SETPOINTS

2.2.1 The Reactor Protection System instrumentation setpoints shall be set consistent with the Allowable Values ~~Trip Setpoint values~~ shown in Table 2.2-1.

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

ACTION:

With a Reactor Protection System instrumentation setpoint less conservative than the value shown in the Allowable Values column of Table 2.2-1, declare the channel inoperable and apply the applicable ACTION statement requirement of Specification 3.3.1.1 until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Allowable Value ~~Trip Setpoint value~~.

Table 2.2-1 Reactor Protection System Instrumentation Trip Setpoints

Functional unit	~~Trip setpoint~~	Allowable values
1. Manual reactor trip	~~Not applicable.~~	Not applicable.
2. High flux	~~104.94% of RATED THERMAL POWER with four pumps operating~~	≤105.1% ~~<104.94%~~ of RATED THERMAL POWER with four pumps operating#*
	~~≤80.6% of RATED THERMAL POWER with three pumps operating~~	≤80.6% of RATED THERMAL POWER with three pumps operating ~~#~~*
3 RC high temperature	~~≤618°F~~	≤618°F#*
4. Flux --△flux/flow (1)	~~Pump trip setpoints not to exceed the limit lines shown in the CORE OPERATING LIMITS REPORT for four and three pump operation.~~	Pump allowable values not to exceed the limit lines shown in the CORE OPERATING LIMITS REPORT for four and three pump operation.*
5. RC low pressure(1)	~~≥1900.0 psig~~	≥1900.0 psig* ~~>1900.0 psig**~~
6. RC high pressure	~~≤2355 psig~~	≤2355.0 psig* ~~<2355.0 psig**~~
7. RC pressure-temperature(1)	~~≥(16.00 T out °F - 7957.5) psig~~	≥(16.00 T out°F - 7957.5) psig#*
8. High flux/number of RC pumps on(1)	~~≤55.1% of RATED THERMAL POWER with one pump operating in each loop~~	≤55.1% of RATED THERMAL POWER with one pump operating in each loop#*
	~~≤0.0% of RATED THERMAL POWER with two pumps operating in one loop and no pumps operating in the other loop~~	≤0.0% of RATED THERMAL POWER with two pumps operating in one loop and no pumps operating in the other loop#*
	~~≤0.0% of RATED THERMAL POWER with no pumps operating or only one pump operating~~	≤0.0% of RATED THERMAL POWER with no pumps operating or only one pump operating#*
9 Containment pressure high	~~≤4 psig~~	≤4 psig#*

Table 2.2-1. (Cont'd)

(1)Trip may be manually bypassed when RCS pressure ≤1820 psig by actuating shutdown bypass provided that:

a. The high flux trip setpoint is ≤5% of RATED THERMAL POWER.

b. The shutdown bypass high pressure trip setpoint of ≤1820 psig is imposed.

c. The shutdown bypass is removed when RCS pressure >1820 psig.

*Allowable value for CHANNEL FUNCTIONAL TEST.

~~**Allowable value for CHANNEL CALIBRATION~~.

~~#Allowable value for CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION.~~

Figure 2.2-1 Trip Setpoint for Flux -- ΔFlux/Flow

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BASES

FOR

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

Figure 2.2-2 Allowable Value for Flux-Δ Flux/Flow

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NOTE

The summary statements contained in this section provide the bases for the specifications of Section 2.0 and are not considered a part of these technical specifications as provided in 10 CFR 50.36.

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2.1.1 AND 2.1.2 REACTOR CORE

The restrictions of this safety limit prevent overheating of the fuel cladding and possible cladding perforation which would result in the release of fission products to the reactor coolant. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Operation above the upper boundary of the nucleate boiling regime would result in excessive cladding temperatures because of the onset of departure from nucleate boiling (DNB) and the resultant sharp reduction in heat transfer coefficient. DNB is not a directly measurable parameter during operation and therefore THERMAL POWER and Reactor Coolant Temperature and Pressure have been related to DNB using critical heat flux (CHF) correlations. The local DNB heat flux ratio, DNBR, defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, is indicative of the margin to DNB.

The B&W-2 and BWC CHF correlations have been developed to predict DNB for axially uniform and non-uniform heat flux distributions. The B&W-2 correlation applies to Mark-B fuel and the BWC correlation applies to all B&W fuel with zircaloy spacer grids. The minimum value of the DNBR during steady state operation, normal operational transients, and anticipated transients is limited to 1.30 (B&W-2) and 1.18 (BWC). The value corresponds to a 95 percent probability at a 95 percent confidence level that DNB will not occur and is chosen as an appropriate margin to DNB for all operating conditions.

The curve presented in Figure 2.1-1 represents the conditions at which a minimum DNBR equal to or greater than the correlation limit is predicted for the maximum possible thermal power 112% when the reactor coolant flow is 380,000 GPM, which is approximately 108% of design flow rate for four operating reactor coolant pumps. (The minimum required measured flow is 389,500 GPM). This curve is based on the design hot channel factors with potential fuel densification and fuel rod bowing effects.

The design limit power peaking factors are the most restrictive calculated at full power for the range from all control rods fully withdrawn to minimum allowable control rod withdrawal, and form the core DNBR design basis.

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SAFETY LIMITS

BASES

The CORE OPERATING LIMITS REPORT includes curves for protective limits for AXIAL POWER IMBALANCE and for nuclear overpower based on reactor coolant system flow. A protective limit is a cycle-specific limit that ensures that a safety limit is not exceeded by requiring operation within both the cycle design (operating) limits and the Reactor Protection System setpoints. These protective limit curves reflect the more restrictive of two thermal limits and account for the effects of potential fuel densification and potential fuel rod bow:

1. The DNBR limit produced by a design nuclear power peaking factor as described in the CORE OPERATING LIMITS REPORT or the combination of the radial peak, axial peak, and position of the axial peak that yields no less than the DNBR limit.

2. The combination of radial and axial peak that causes central fuel melting at the hot spot. The limits for all fuel designs during the operating cycle are listed in the CORE OPERATING LIMITS REPORT.

Power peaking is not a directly observable quantity and therefore limits have been established on the basis of the reactor power imbalance produced by the power peaking.

The specified flow rates for the CORE OPERATING LIMITS REPORT curves for protective limits for AXIAL POWER IMBALANCE and for nuclear overpower based on reactor coolant system flow correspond to the analyzed minimum flow rates with four pumps and three pumps, respectively.

The curve of Figure 2.1-1 is the most restrictive of all possible reactor coolant pump-maximum thermal power combinations shown in BASES Figure 2.1. The curves of BASES Figure 2.1 represent the conditions at which a minimum DNBR equal to the DNBR limit is predicted at the maximum possible thermal power for the number of reactor coolant pumps in operation or the local quality at the point of minimum DNBR is equal to the corresponding DNB correlation quality limit (+22% (B&W-2) or +26% (BWC)), whichever condition is more restrictive.

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For the curve of BASES Figure 2.1, a pressure-temperature point above and to the left of the curve would result in a DNBR greater than 1.30 (B&W-2) or 1.18 (BWC) and a local quality at the point of minimum DNBR less than +22% (B&W-2) or +26% (BWC) for that particular reactor coolant pump situation. The DNBR curve for three pump operation is less restrictive than the four pump curve.

2.1.3 REACTOR COOLANT SYSTEM PRESSURE

The restriction of this Safety Limit protects the integrity of the Reactor Coolant System from overpressurization and thereby prevents the release of radionuclides contained in the reactor coolant from reaching the containment atmosphere.

The reactor pressure vessel and pressurizer are designed to Section III of the ASME Boiler and Pressure Vessel Code which permits a maximum transient pressure of 110%, 2750 psig, of design pressure. The Reactor Coolant System piping, valves and fittings, are designed to ANSI B 31.7, 1968 Edition, which permits a maximum transient pressure of 110%, 2750 psig, of component design pressure. The Safety Limit of 2750 psig is therefore consistent with the design criteria and associated code requirements.

The entire Reactor Coolant System is hydrotested at 3[illegible] psig, 125% of design pressure, to demonstrate integrity prior to initial operation.

2.2 LIMITING SAFETY SYSTEM SETTINGS

BASES

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

The reactor protection system instrumentation Allowable Values ~~trip setpoints~~ specified in Table 2.2-1 ~~are the values at which the reactor trips are set for each parameter. The trip setpoints~~ have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their safety limits.

The shutdown bypass provides for bypassing certain functions of the reactor protection system in order to permit control rod drive tests, zero power PHYSICS TESTS and certain startup and shutdown procedures. The purpose of the shutdown bypass high pressure trip is to prevent normal operation with shutdown bypass activated. This high pressure ~~trip~~ setpoint is lower than the normal low pressure ~~trip~~ setpoint so that the reactor must be tripped before the bypass is initiated. The high flux ~~trip~~ setpoint of ≤5.0% prevents any significant reactor power from being produced. Sufficient natural circulation would be available to remove 5.0% of RATED THERMAL POWER if none of the reactor coolant pumps were operating.

Manual Reactor Trip

The manual reactor trip is a redundant channel to the automatic reactor protection system instrumentation channels and provides manual reactor trip capability.

High Flux

A high flux trip at high power level (neutron flux) provides reactor core protection against reactivity excursions which are too rapid to be protected by temperature and pressure protective circuitry.

During normal station operation, reactor trip is initiated when the reactor power level reaches the Allowable Value ≤ 105.1% of ~~104.94%~~ rated power. Due to transient overshoot, heat balance, and instrument errors, the maximum actual power at which a trip would be actuated could be 112%, which was used in the safety analysis.

LIMITING SAFETY SYSTEM SETTINGS

BASES

RC High Temperature

The RC high temperature trip ≤618°F prevents the reactor outlet temperature from exceeding the design limits and acts as a backup trip for all power excursion transients.

Flux -- ΔFlux/Flow

The power level Allowable Value ~~trip setpoint~~ produced by the reactor coolant system flow is based on a flux-to-flow ratio which has been established to accommodate flow decreasing transients from high power where protection is not provided by the high flux/number of reactor coolant pumps on trips.

The power level Allowable Value ~~trip setpoint~~ produced by the power-to-flow ratio provides both high power level and low flow protection in the event the reactor power level increases or the reactor coolant flow rate decreases. The power level setpoint produced by the power-to-flow ratio provides overpower DNB protection for all modes of pump operation. For every flow rate there is a maximum permissible power level, and for every power level there is a minimum permissible low flow rate.

For safety calculations the instrumentation errors for the power level were used. Full flow rate is defined as the flow calculated by the heat balance at 100% power. At the time of the calibration the RCS flow will be greater than or equal to the value in Table 3.2-2.

LIMITING SAFETY SYSTEM SETTINGS

BASES

The AXIAL POWER IMBALANCE boundaries are established in order to prevent reactor thermal limits from being exceeded. These thermal limits are either power peaking kW/ft limits or DNBR limits. The AXIAL POWER IMBALANCE reduces the power level trip produced by a flux-to-flow ratio such that the boundaries of the figure in the CORE OPERATING LIMITS REPORT are produced.

RC Pressure - Low, High, and Pressure Temperature

The high and low trips are provided to limit the pressure range in which reactor operation is permitted.

During a slow reactivity insertion startup accident from low power or a slow reactivity insertion from high power, the RC high pressure setpoint is reached before the high flux ~~trip~~ setpoint. The Allowable Value ~~trip setpoint~~ for RC high pressure, 2355 psig, has been established to maintain the system pressure below the safety limit, 2750 psig, for any design transient. The RC high pressure trip is backed up by the pressurizer code safety valves for RCS over pressure protection, and is therefore set lower than the set pressure for these valves, < 2525 psig. The RC high pressure trip also backs up the high flux trip.

The RC low pressure, 1900.0 psig, and RC pressure-temperature (16.00 Tout - 7957.5) psig, Allowable Values ~~trip setpoints~~ have been established to maintain the DNB ratio greater than or equal to the minimum allowable DNB ratio for those design accidents that result in a pressure reduction. It also prevents reactor operation at pressures below the valid range of DNB correlation limits, protecting against DNB.

High Flux/Number of Reactor Coolant Pumps On

In conjunction with the flux - Δflux/flow trip the high flux/number of reactor coolant pumps on trip prevents the minimum core DNBR from decreasing below the minimum allowable DNB ratio by tripping the reactor due to the loss of reactor coolant pump(s). The pump monitors also restrict the power level for the number of pumps in operation.

LIMITING SAFETY SYSTEM SETTINGS

BASES

Containment High Pressure

The Containment High Pressure Allowable Value ~~Trip Setpoint~~ ≤ 4 psig, provides positive assurance that a reactor trip will occur in the unlikely event of a steam line failure in the containment vessel or a loss-of-coolant accident, even in the absence of a RC Low Pressure trip.

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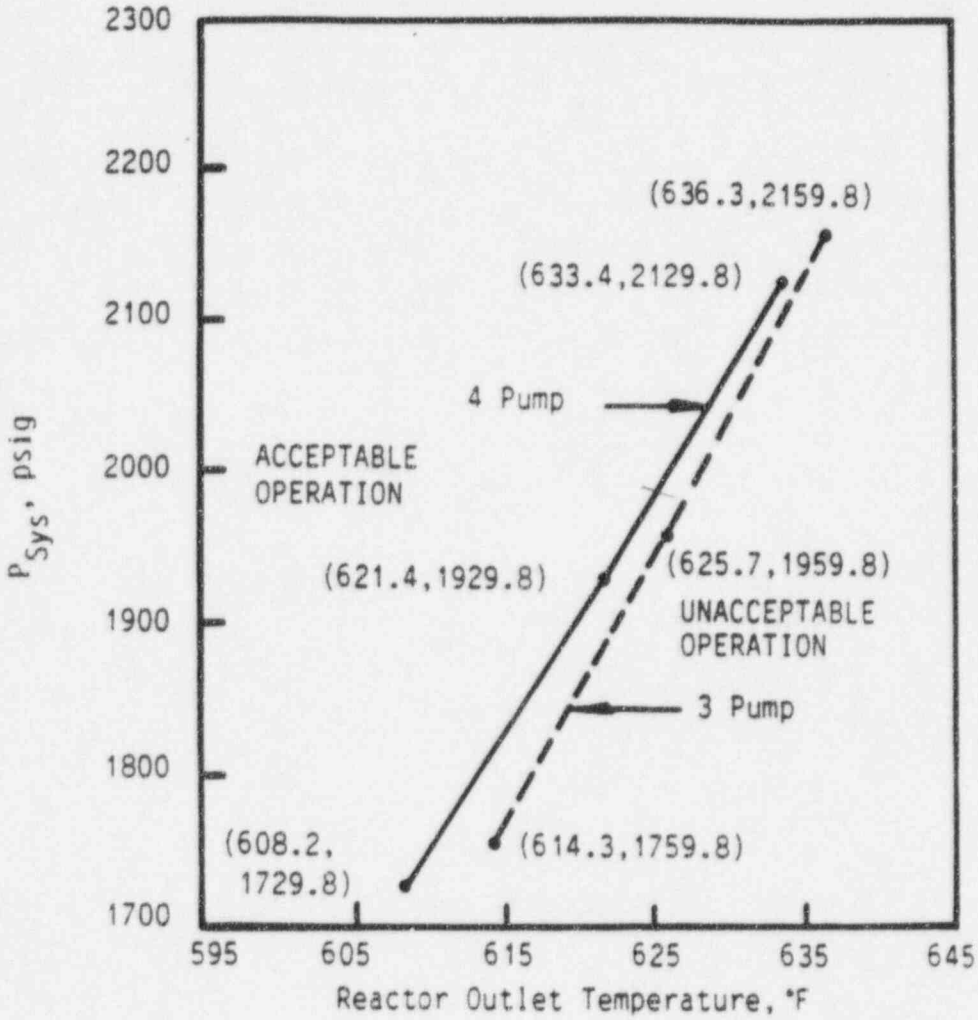
Bases Figure 2.1 Pressure/Temperature Limits at Maximum Allowable Power for Minimum DNBR



Pumps	Flow, gpm	Power	Required Measured Flow to ensure Compliance, gpm
4	380,000	112%	389,500
3	283,860	90.5%	290,957

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3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1.1 As a minimum, the Reactor Protection System instrumentation channels and bypasses of Table 3.3-1 shall be OPERABLE with RESPONSE TIMES as shown in Table 3.3-2.

APPLICABILITY: As shown in Table 3.3-1.

ACTION:

As shown in Table 3.3-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1.1 Each Reactor Protection System instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the MODES and at the frequencies shown in Table 4.3-1.

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4.3.1.1.2 The total bypass function shall be demonstrated OPERABLE at least once per 18 months during CHANNEL CALIBRATION testing of each channel affected by bypass operation.

4.3.1.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip function shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least one channel per function such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip function as shown in the "Total No. of Channels" column of Table 3.3-1.

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TABLE 3.3-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Manual Reactor Trip	2	1	2	1, 2 and *	1
2. High Flux	4	2	3	1, 2	2#, 10
3. RC High Temperature	4	2	3	1, 2	3#, 10
4. Flux - ΔFlux - Flow	4	2(a)(b)	3	1, 2	2#, 10
5. RC Low Pressure	4	2(a)	3	1, 2	3#, 10
6. RC High Pressure	4	2	3	1, 2	3#, 10
7. RC Pressure-Temperature	4	2(a)	3	1, 2	3#, 10
8. High Flux/Number of Reactor Coolant Pumps On	4	2(a)(b)	3	1, 2	3#, 10
9. Containment High Pressure	4	2	3	1, 2	3#, 10
10. Intermediate Range, Neutron Flux and Rate	2	N/A	2(c)	1, 2 and *	4
11. Source Range, Neutron Flux and Rate					
A. Startup	2	N/A	2	2## and *	5
B. Shutdown	2	N/A	1	3, 4 and 5	6
12. Control Rod Drive Trip Breakers	2 per trip system	1 per trip system	2 per trip system	1, 2 and *	7#, 8#
13. Reactor Trip Module	2 per trip system	1 per trip system	2 per trip system	1, 2 and *	7#
14. Shutdown Bypass High Pressure	4	2	3	2**, 3** 4**, 5**	6#
15. SCR Relays	2	2	2	1, 2 and *	9#

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TSIR 90-0001

TABLE 3.3-1 (Continued)

TABLE NOTATION

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

**When Shutdown Bypass is actuated.

#The provisions of Specification 3.0.4 are not applicable.

##High voltage to detector may be de-energized above 10^{-10} amps on both Intermediate Range channels.

(a) Trip may be manually bypassed when RCS pressure ≤ 1820 psig by actuating Shutdown Bypass provided that:

(1) The High Flux Trip Setpoint is ≤ 5% of RATED THERMAL POWER,

(2) The Shutdown Bypass High Pressure Trip Setpoint of ≤ 1820 psig is imposed, and

(3) The Shutdown Bypass is removed when RCS pressure > 1820 psig.

(b) Trip may be manually bypassed when Specification 3.10.3 is in effect.

(c) The minimum channels OPERABLE requirement may be reduced to one when Specification 3.10.1 or 3.10.2 is in effect.

ACTION STATEMENTS

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

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

a. The inoperable channel is placed in the bypassed or tripped condition within one hour.

b. Either, THERMAL POWER is restricted to ≤ 75% of RATED THERMAL POWER and the High Flux Trip Setpoint is reduced to ≤ 85% of RATED THERMAL POWER within 4 hours or the QUADRANT POWER TILT is monitored at least once per 12 hours.

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TABLE 3.3-1 (Continued)

ACTION STATEMENTS (Continued)

ACTION 3 - With the number of OPERABLE channels one less than the Total Number of Channels STARTUP and POWER OPERATION may proceed provided the inoperable channel is placed in the bypassed or tripped condition within one hour.

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

a. ≤ 5% of RATED THERMAL POWER restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above 5% of RATED THERMAL POWER.

b. > 5% of RATED THERMAL POWER, POWER OPERATION may continue.

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TABLE 3.3-1 (Continued)

ACTION STATEMENTS (Continued)

ACTION 5 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement and with the THERMAL POWER level:

a. $\leq 10^{-10}$ amps on the Intermediate Range (IR) instrumentation, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above 10^{-10} amps on the IR instrumentation.

b. $> 10^{-10}$ amps on the IR instrumentation, operation may continue.

ACTION 6 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, verify compliance with the SHUTDOWN MARGIN requirements of Specification 3.1.1.1 within one hour and at least once per 12 hours thereafter.

ACTION 7 - With the number of OPERABLE channels one less than the Total Number of Channels STARTUP and/or POWER OPERATION may proceed provided all of the following conditions are satisfied: TSIR 89-0014

a. Within 1 hour:

1. Place the inoperable channel in the tripped condition, or

2. Remove power supplied to the control rod trip device associated with the inoperative channel.

b. One additional channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.1.1.1, and the inoperable channel above may be bypassed for up to 30 minutes in any 24 hour period when necessary to test the trip breaker associated with the logic of the channel being tested per Specification 4.3.1.1.1. The inoperable channel above may not be bypassed to test the logic of a channel of the trip system associated with the inoperable channel.

TABLE 3.3-1 (Continued)

ACTION STATEMENTS (Continued)

ACTION 8 - With one of the Reactor Trip Breaker diverse trip features (undervoltage or shunt trip devices) inoperable, restore it to OPERABLE status in 48 hours or place the breaker in trip in the next hour.

ACTION 9 - With one or both channels of SCR Relays inoperable, restore the channels to OPERABLE status during the next COLD SHUTDOWN exceeding 24 hours.

ACTION 10 - With the number of channels OPERABLE one less than the Minimum Channels OPERABLE requirement, within one hour, place one inoperable channel in trip and the second inoperable channel in bypass, and restore one of the inoperable channels to OPERABLE status within 48 hours or be in HOT STANDBY within the next 6 hours and open the reactor trip breakers.

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TABLE 3.3-2

REACTOR PROTECTION SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIMES** (seconds)
1. Manual Reactor Trip	Not Applicable
2. High Flux*	≤ 0.266
3. RC High Temperature	Not Applicable
4. Flux - Δ Flux - Flow* - Variable Flow	≤ 1.77
- Constant Flow	≤ 0.266
5. RC Low Pressure	≤ 0.341
6. RC High Pressure	≤ 0.341
7. RC Pressure - Temperature - Constant Temperature	Not Applicable
8. High Flux/Number of Reactor Coolant Pumps On*	≤ 0.631***
9. Containment High Pressure	Not Applicable

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

** Including sensor (except as noted), RPS instrument delay and the breaker delay.

*** A 0.24 sec delay time has been assumed for pump monitor.

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TABLE 4.3-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	S/U(1)	N.A.
2. High Flux	S	D(2), and Q(6,9)	N.A.	1, 2
3. RC High Temperature	S	R	SA(9)	1, 2
4. Flux - ΔFlux - Flow	S(4)	M(3) and Q(6,7,9)	N.A.	1, 2
5. RC Low Pressure	S	R	SA(9)	1, 2
6. RC High Pressure	S	R	SA(9)	1, 2
7. RC Pressure-Temperature	S	R	SA(9)	1, 2
8. High Flux/Number of Reactor Coolant Pumps On	S	Q(6,9)	N.A.	1, 2
9. Containment High Pressure	S	R	SA(9)	1, 2
10. Intermediate Range, Neutron Flux and Rate	S	R(6)	N.A.(5)	1, 2 and *
11. Source Range, Neutron Flux and Rate	S	R(6)	N.A.(5)	2, 3, 4 and 5
12. Control Rod Drive Trip Breakers	N.A.	N.A.	M(8,9) and S/U(1)(8)	1, 2 and *
13. Reactor Trip Module Logic	N.A.	N.A.	M(9)	1, 2 and *
14. Shutdown Bypass High Pressure	S	R	SA(9)	2**, 3**, 4**, 5**
15. SCR Relays	N.A.	N.A.	R	1, 2 and *

TABLE 4.3-1 (Continued)

NOTATION

(1) - If not performed in previous 7 days.

(2) - Heat balance only, above 15% of RATED THERMAL POWER.

(3) - When THERMAL POWER [TP] is above 50% of RATED THERMAL POWER [RTP] and at a steady state, compare out-of-core measured AXIAL POWER IMBALANCE [API_o] to incore measured AXIAL POWER IMBALANCE [API_I] as follows:

$$\frac{RTP}{TP} [API_o - API_I] = \text{Offset Error}$$

Recalibrate if the absolute value of the Offset Error is $\geq$ 2.5%.

(4) - AXIAL POWER IMBALANCE and loop flow indications only.

(5) - CHANNEL FUNCTIONAL TEST is not applicable. Verify at least one decade overlap prior to each reactor startup if not verified in previous 7 days.

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

(7) - Flow rate measurement sensors may be excluded from CHANNEL CALIBRATION. However, each flow measurement sensor shall be calibrated at least once each REFUELING INTERVAL ~~per 18 months~~.

(8) - The CHANNEL FUNCTIONAL TEST shall independently verify the OPERABILITY of both the undervoltage and shunt trip devices of the Reactor Trip Breakers.

(9) - Performed on a STAGGERED TEST BASIS.

* - With any control rod drive trip breaker closed.

** - When Shutdown Bypass is actuated.

ADDITIONAL CHANGES PREVIOUSLY PROPOSED BY LETTER
Serial No. 2405 Date 12/11/96

INSTRUMENTATION

STEAM AND FEEDWATER RUPTURE CONTROL SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2.2 The Steam and Feedwater Rupture Control System (SFRCS) instrumentation channels shown in Table 3.3-11 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3-12, with the exception of the Steam Generator Level-Low Functional Unit which shall be set consistent with the Allowable Value column of Table 3.3-12, and with RESPONSE TIMES as shown in Table 3.3-13.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With a SFRCS instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3-12, declare the channel inoperable and apply the applicable ACTION requirement of Table 3.3-11, until the channel is restored to OPERABLE status with the trip setpoint adjusted consistent with Table 3.3-12. ~~the Trip Setpoint value.~~

b. With a SFRCS instrumentation channel inoperable, take the action shown in Table 3.3-11.

SURVEILLANCE REQUIREMENTS

4.3.2.2.1 Each SFRCS instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST during the MODES and at the frequencies shown in Table 4.3-11.
4.3.2.2.2 The logic for the bypasses shall be demonstrated OPERABLE during the at power CHANNEL FUNCTIONAL TEST of channels affected by bypass operation. The total bypass function shall be demonstrated OPERABLE at least once per 18 months during CHANNEL CALIBRATION testing of each channel affected by bypass operation.

4.3.2.2.3 The STEAM AND FEEDWATER RUPTURE CONTROL SYSTEM RESPONSE TIME of each SFRCS function shall be demonstrated to be within the limit at least once per 18 months. Each test shall include at least one channel per function such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific SFRCS function as shown in the "Total No. of Channels" Column of Table 3.3-11.

TABLE 3.3-11

STEAM AND FEEDWATER RUPTURE CONTROL SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	ACTION
1. Main Steam Pressure Low Instrument Channels*	2	1	2	16#
a. PS 3689B Steam Line 1 Channel 1				
b. PS 3689D Steam Line 2 Channel 1				
c. PS 3689F Steam Line 1 Channel 1				
d. PS 3689H Steam Line 2 Channel 1				
e. PS 3687A Steam Line 2 Channel 2				
f. PS 3687C Steam Line 1 Channel 2				
g. PS 3687E Steam Line 2 Channel 2				
h. PS 3687G Steam Line 1 Channel 2				

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TABLE 3.3-11 (Continued)

STEAM AND FEEDWATER RUPTURE CONTROL SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	ACTION
2. Feedwater/Steam Generator Differential Pressure - High Instrument Channels	2	1	2	16
a. PDS 2685A Feedwater/Steam Generator 2 Channel 2 PDS 2685B Feedwater/Steam Generator 2 Channel 2				
b. PDS 2685C Feedwater/Steam Generator 2 Channel 1 PDS 2685D Feedwater/Steam Generator 2 Channel 1				
c. PDS 2686A Feedwater/Steam Generator 1 Channel 1 PDS 2686B Feedwater/Steam Generator 1 Channel 1				
d. PDS 2686C Feedwater/Steam Generator 1 Channel 2 PDS 2686D Feedwater/Steam Generator 1 Channel 2				
3. Steam Generator Level - Low Instrument Channels	2	1	2	16
a. LSLL SP9B8 Steam Generator 1 Channel 1 LSLL SP9B9 Steam Generator 1 Channel 1				
b. LSLL SP9A6 Steam Generator 2 Channel 1 LSLL SP9A7 Steam Generator 2 Channel 1				
c. LSLL SP9A8 Steam Generator 2 Channel 2 LSLL SP9A9 Steam Generator 2 Channel 2				

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TABLE 3.3-11 (Continued)

STEAM AND FEEDWATER RUPTURE CONTROL SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	ACTION
3. Steam Generator Level - Low Instrument Channels (continued)				
d. LSLL SP9B6 Steam Generator 1 Channel 2 LSLL SP9B7 Steam Generator 1 Channel 2				
4. Loss of RCP Channels	2	1	2	16
5. Manual Initiation (Push buttons)				
a. Initiate AFPT #1	1	1	1	17
b. Initiate AFPT #2	1	1	1	
c. Initiate AFPT #1 and Isolate SG #1	1	1	1	
d. Initiate AFPT #2 and Isolate SG #2	1	1	1	

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TABLE 3.3-11 (Continued)

TABLE NOTATION

* May be bypassed when steam pressure is below 750 psig. Bypass shall be automatically removed when the steam pressure exceeds 800 psig.

\# The provisions of Specification 3.0.4 are not applicable.

ACTION STATEMENTS

ACTION 16 - With the number of OPERABLE Channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed until performance of the next required CHANNEL FUNCTIONAL TEST provided the inoperable section of the channel is placed in the tripped condition within 1 hour.

ACTION 17 - With the number of OPERABLE Channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

TABLE 3.3-12

STEAM AND FEEDWATER RUPTURE CONTROL SYSTEM
INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNITS	TRIP SETPOINTS	ALLOWABLE VALUES
1. Steam Line Pressure - Low	≥ 591.6 psig	≥ 591.6 psig* ≥ 586.6 psig**
2. Steam Generator Level - Low [1]	~~≥ 16.4"~~ N.A.	≥ ~~16.9"*~~ ~~15.6"*~~ ~~≥ 12.9"**~~
3. Steam Generator Feedwater Differential Pressure - High [2]	≤ 197.6 psid	≤ 197.6 psid* ≤ 199.6 psid**
4. Reactor Coolant Pumps - Loss of	High ≤ 1384.6 amps Low ≥ 106.5 amps	≤ 1384.6 amps# ≥ 106.5 amps#

[1] Actual water level above the lower steam generator tubesheet.
[2] Where differential pressure is steam generator minus feedwater pressure.
*Allowable Value for CHANNEL FUNCTIONAL TEST
**Allowable Value for CHANNEL CALIBRATION
#Allowable Value for CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION

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TABLE 3.3-13

STEAM AND FEEDWATER RUPTURE CONTROL SYSTEM RESPONSE TIMES

ACTUATED EQUIPMENT	RESPONSE TIME IN SECONDS
1. Auxiliary Feed Pump	≤ 40
2. Main Steam Isolation Valves*	
a. Main Steam Low Pressure Channels	≤ 6
b. Feedwater/Steam Generator High Differential Pressure Channels	≤ 6.5
3. Main Feedwater Valves	
a. Main Control	≤ 8
b. Startup Control	≤ 13
c. Stop Valve	≤ 16
4. Turbine Stop Valves**	≤ 1

* The response time is to be the time elapsed from the monitored variable exceeding the trip setpoint until the MSIV is fully closed.

** The response time is to be the time elapsed from the main steam line low pressure trip condition until the TSV is fully closed.

TABLE 4.3-11

STEAM AND FEEDWATER RUPTURE CONTROL SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST
1. Instrument Channel			
a. Steam Line Pressure - Low	S	R	M
b. Steam Generator Level - Low	S	R	M
c. Steam Generator - Feedwater Differential Pressure - High	S	R	M
d. Reactor Coolant Pumps - Loss of	S	R	M
2. Manual Actuation	NA	NA	R

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INSTRUMENTATION

REMOTE SHUTDOWN INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.5.1 The remote shutdown monitoring instrumentation channels shown in Table 3.3-9 shall be OPERABLE with readouts displayed external to the control room.

3.3.3.5.2 The control circuits and transfer switches required for a serious control room or cable spreading room fire shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With the number of OPERABLE remote shutdown monitoring channels less than required by Table 3.3-9, either restore the inoperable channel to OPERABLE status within 30 days, or be in HOT SHUTDOWN within the next 12 hours.

b. With one or more control circuits or transfer switches required for a serious control room or cable spreading room fire inoperable, restore the inoperable circuit(s) or switch(es) to OPERABLE status within 30 days, or prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 30 days outlining the action taken, the cause of the inoperability, and the plans and schedule for restoring the circuit(s) or switch(es) to OPERABLE status.

c. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.5.1 Each remote shutdown monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3-6.

4.3.3.5.2 At least once per 18 months, verify each control circuit and transfer switch required for a serious control room or cable spreading room fire is capable of performing the intended function.

TABLE 3.3-9

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

INSTRUMENT	READOUT LOCATION	MEASUREMENT RANGE	MINIMUM CHANNELS OPERABLE
1. Reactor Trip Breaker Indication	(a) 480v F&DC CH. 2 Switchgear Room	OPEN-CLOSE	(a) 1 (Trip Breaker A)
	(b) 480v E&DC CH. 1 Switchgear Room		(b) 1 (Trip Breaker B)
	(c) 480v F&DC CH. 2 Switchgear Room		(c) 1 (Trip Breaker C)
	(d) CRDC Cabinet Room		(d) 1 (Trip Breaker D)
2. Reactor Coolant Temperature - Hot Leg	Aux. Shutdown Panel	520-620 °F	1
3. Reactor Coolant System Pressure	Aux. Shutdown Panel	0-3000 psig	1
4. Pressurizer Level	Aux. Shutdown Panel	0-320 inches	1
5. Steam Generator Outlet Steam Pressure	Aux. Shutdown Panel	0-1200 psig	1/steam generator
6. Steam Generator Level Startup Range	Aux. Shutdown Panel	0-250 inches	1/steam generator
7. Control Rod Position Switches	Control Rod Drive Control Cabinets, System Logic Cabinet #4	0, 25, 50, 75 and 100%	1/rod

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TABLE 4.3-6

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Reactor Trip Breaker Indication	M	N.A.
2. Reactor Coolant Temperature-Hot Legs	M	R
3. Reactor Coolant System Pressure	M	R
4. Pressurizer Level	M	R
5. Steam Generator Outlet Steam Pressure	M	R
6. Steam Generator Startup Range Level	M	R
7. Control Rod Position Switches	M	N.A.

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INSTRUMENTATION

POST-ACCIDENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.6 The post-accident monitoring instrumentation channels shown in Table 3.3-10 shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With the number of OPERABLE post-accident monitoring instrumentation channels less than the Minimum Channels OPERABLE required by Table 3.3-10, either restore the inoperable channel to OPERABLE status within 30 days, or be in HOT SHUTDOWN within the next 12 hours.

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.6 Each post-accident monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3-10. TSIR 89-0006

TABLE 3.3-10

POST-ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE
1. SG Outlet Steam Pressure	1/Steam Generator
2. RC Loop Outlet Temperature	2/Loop
3. RC Loop Pressure	2/Loop
4. Pressurizer Level	2
5. SG Startup Range Level	2/Steam Generator
6. Containment Vessel Post-Accident Radiation	2
7. High Pressure Injection Flow	1/Channel
8. Low Pressure Injection (DHR) Flow	1/Channel
9. Auxiliary Feedwater Flow Rate	2/Steam Generator
10. RC System Subcooling Margin Monitor	1
11. PORV Position Indicator	1
12. PORV Block Valve Position Indicator	1
13. Pressurizer Safety Valve Position Indicator	1/Valve
14. BWST Level	3
15. Containment Normal Sump Level	1
16. Containment Wide Range Water Level	1

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TABLE 3.3-10 (Continued)

POST-ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE
17. Containment Wide Range Pressure	1
18. Incore Thermocouples	2 per core quadrant
19. Reactor Coolant Hot Leg Level (Wide Range)	1
20. Neutron Flux (Wide Range)	1
21. Neutron Flux (Source Range)	1

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TABLE 4.3-10

POST-ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT		CHANNEL CHECK	CHANNEL CALIBRATION
1.	SG Outlet Steam Pressure	M	R
2.	RC Loop Outlet Temperature	M	R
3.	RC Loop Pressure	M	R
4.	Pressurizer Level	M	R
5.	SG Startup Range Level	M	R
6.	Containment Vessel Post-Accident Radiation	~~M~~	~~R~~
	a.) Containment High Range Radiation	M	R
	b.) Containment Wide Range Noble Gas	M	E
7.	High Pressure Injection Flow	M	R
8.	Low Pressure Injection (DHR) Flow	M	R
9.	Auxiliary Feedwater Flow Rate	M	R
10.	RC System Subcooling Margin Monitor	M	R
11.	PORV Position Indicator	M	R
12.	PORV Block Valve Position Indicator	M	R
13.	Pressurizer Safety Valve Position Indicator	M	R
14.	BWST Level	S	R
15.	Containment Normal Sump Level	M	R

ADDITIONAL CHANGES PREVIOUSLY PROPOSED BY LETTER
Serial No. 2425 Date 12/11/96

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TABLE 4.3-10 (Continued)

POST-ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
17. Containment Wide Range Pressure	M	R
18. Incore Thermocouples	M	R
19. Reactor Coolant Hot Leg Level (Wide Range)	M	R
20. Neutron Flux (Wide Range)	M	R**
21. Neutron Flux (Source Range)	M	R**

** Neutron detectors may be excluded from CHANNEL CALIBRATION.

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Pages 3/4 3-51 through 3/4 3-56 deleted. Next page is 3/4 3-57.

ADDITIONAL CHANGES PREVIOUSLY PROPOSED BY LETTER
Serial No. 2325 Date 9/29/95

REACTOR COOLANT SYSTEM

SAFETY VALVES AND PILOT OPERATED RELIEF VALVE - OPERATING

LIMITING CONDITION FOR OPERATION

3.4.3 All pressurizer code safety valves shall be OPERABLE with a lift setting of ≤ 2525 psig.* When not isolated, the pressurizer pilot operated relief valve shall have a trip setpoint of ≥ 2435 psig and an allowable value of ≥2435 psig.**

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With one pressurizer code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes or be in HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.3 For the pressurizer code safety valves, there are no additional Surveillance Requirements other than those required by Specification 4.0.5. For the pressurizer pilot operated relief valve a CHANNEL CALIBRATION check shall be performed each REFUELING INTERVAL ~~every 18 months~~.

* The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

** Allowable value for CHANNEL CALIBRATION check.

Figure 3.4-2a

Reactor Coolant System Pressure - Pressurizer Level Limits for inoperable Decay Heat Removal System Relief Valve in MODE 4

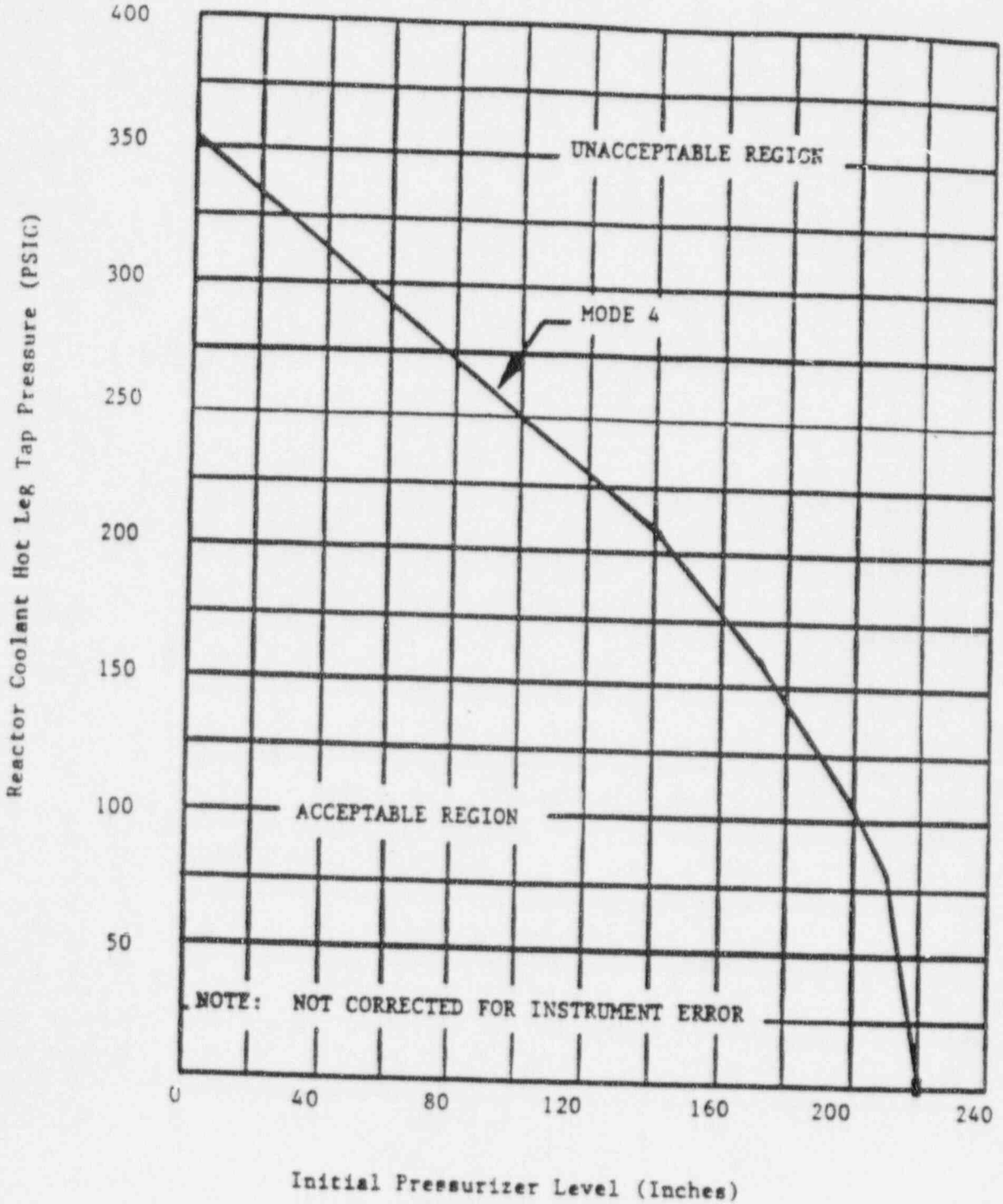

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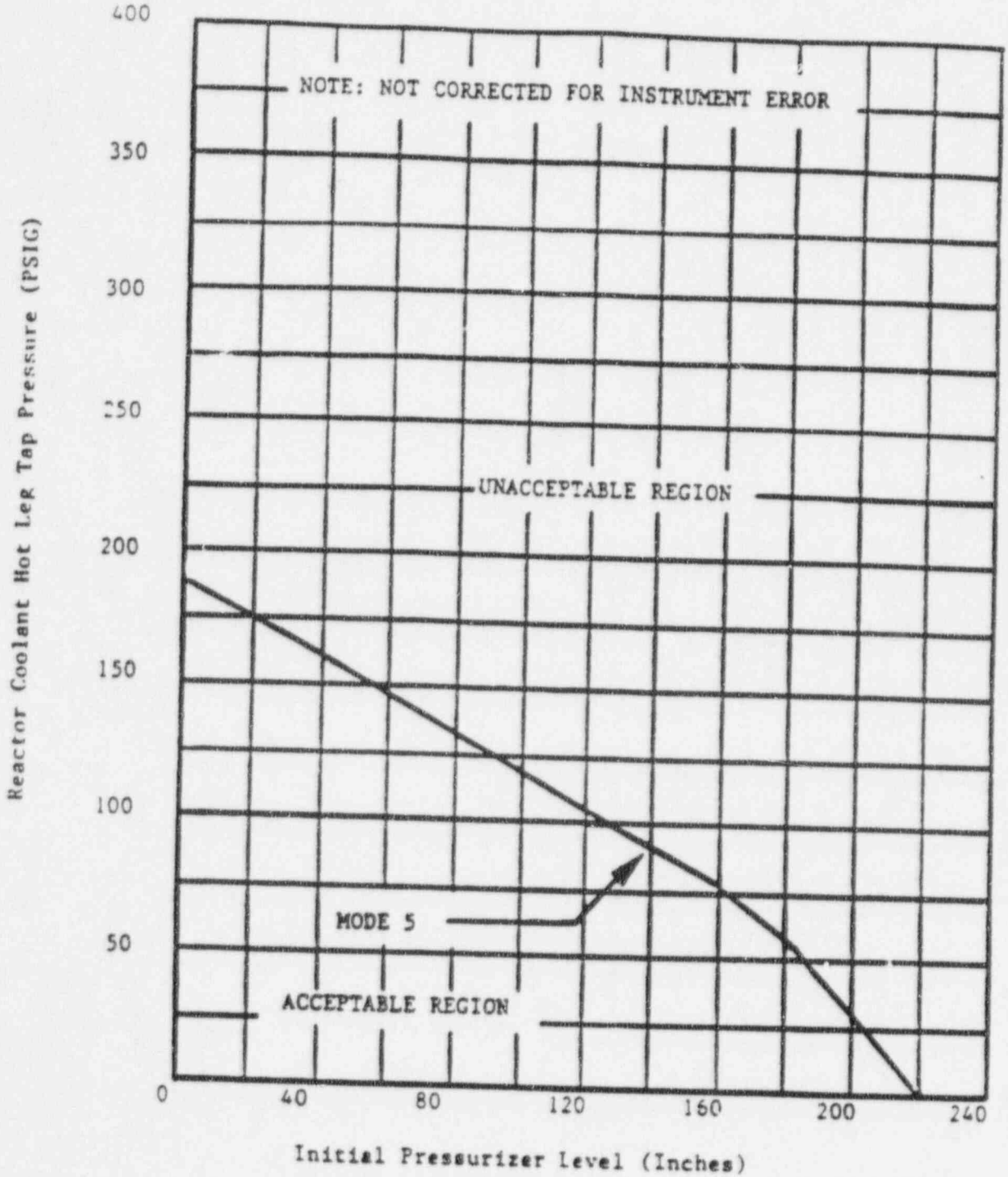
Figure 3.4-2b

Reactor Coolant System Pressure - Pressurizer Level Limits for inoperable Decay Heat Removal System Relief Value in MODE 5



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REACTOR COOLANT SYSTEM

3/4.4.6 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.6.1 The following Reactor Coolant System leakage detection systems shall be OPERABLE:

a. The containment atmosphere particulate radioactivity monitoring system,

b. The containment sump level and flow monitoring system, and

c. The containment atmosphere gaseous radioactivity monitoring system.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With only two of the above required leakage detection systems OPERABLE, operation may continue for up to 30 days provided grab samples are obtained and analyzed at least once per 24 hours when the required gaseous or particulate radioactivity monitoring system is inoperable; otherwise be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.1 The leakage detection systems shall be demonstrated OPERABLE by:

a. Containment atmosphere particulate monitoring system-performance of CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST at the frequencies specified in Table 4.3-3.

REACTOR COOLANT SYSTEM

SURVEILLANCE REQUIREMENTS (Continued)

b. Containment sump level and flow monitoring system-performance of CHANNEL CALIBRATION at least once each REFUELING INTERVAL ~~per 18 months~~.

c. Containment atmosphere gaseous monitoring system-performance of CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST at the frequencies specified in Table 4.3-3.

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PLANT SYSTEMS

AUXILIARY FEEDWATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.2 Two trains of auxiliary feedwater, each consisting of an auxiliary feedwater pump and associated flow path to both steam generators, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one train of auxiliary feedwater inoperable to either or both steam generator(s), restore the inoperable train to OPERABLE status within 72 hours or be in HOT SHUTDOWN within the next 12 hours.

b. With any Auxiliary Feed Pump Turbine Inlet Steam Pressure Interlocks inoperable, restore the inoperable interlocks to OPERABLE status within 7 days or be in HOT SHUTDOWN within the next 12 hours.

c. With steam generator inlet valve AF 599 or AF 608 closed, re-open the closed valve AF 599 or AF 608 within one hour or be in HOT STANDBY within the next 6 hours and HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.2.1 Each Auxiliary Feedwater train shall be demonstrated OPERABLE:

a. At least once per 92 days on a STAGGERED TEST BASIS by:*

1. Verifying the differential pressure of each steam turbine driven pump is greater than or equal to the required differential pressure at the specified recirculation flow rate. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3.

---

* When conducting tests of an auxiliary feedwater train in MODES 1, 2, and 3 which require local manual realignment of valves that make the train inoperable, the Motor Driven Feedwater Pump and its associated flow paths shall be OPERABLE per Specification 3.7.1.7 during the performance of this surveillance. If the Motor Driven Feedwater Pump or an associated flow path is inoperable, a dedicated individual shall be stationed at the realigned auxiliary feedwater train's valves (in communication with the control room) able to restore the valves to normal system OPERABLE status.

ADDITIONAL CHANGES PREVIOUSLY PROPOSED BY LETTER
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PLANT SYSTEMS

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 31 days on a STAGGERED TEST BASIS by:

1. Verifying that each valve (power operated or automatic) in the flow path is in its correct position.

2. Verifying that all manual valves in the auxiliary feedwater pump suction and discharge lines that affect the system's capacity to deliver water to the steam generator are locked in their proper position.

3. Verifying that valves CW 196, CW 197, FW 32, FW 91 and FW 106 are closed.

c. At least once per 18 months by:

1. Verifying that each automatic valve in the flow path actuates to its correct position on a Steam and Feedwater Rupture Control System actuation test signal.

2. Verifying that each pump starts automatically upon receipt of a Steam and Feedwater Rupture Control System actuation test signal. The provisions of Specification 4.0.4 are not applicable for entry in MODE 3.

3. Verifying that there is a flow path from each auxiliary feedwater pump to both steam generators by pumping water from the Condensate Storage Tank with each pump to both steam generators.

The flow paths shall be verified by either steam generator level change or Auxiliary Feedwater Safety Grade Flow Indication. Verification of the Auxiliary Feedwater System's flow capacity is not required.

d. The Auxiliary Feed Pump Turbine Steam Generator Level Control System shall be demonstrated OPERABLE by performance of a CHANNEL CHECK at least once per 12 hours, a CHANNEL FUNCTIONAL TEST at least once per 31 days, and a CHANNEL CALIBRATION at least once each REFUELING INTERVAL ~~per 18 months~~.

e. The Auxiliary Feed Pump Suction Pressure Interlocks shall be demonstrated OPERABLE by performance of a CHANNEL FUNCTIONAL TEST at least once per 31 days, and a CHANNEL CALIBRATION at least once each REFUELING INTERVAL ~~per 18 months~~.

SURVEILLANCE REQUIREMENTS (Continued)

f. After any modification or repair to the Auxiliary Feedwater System that could affect the system's capability to deliver water to the steam generator, the affected flow path shall be demonstrated available as follows:

1. If the modification or repair is downstream of the test flow line, each auxiliary feed pump(s) associated with the affected flow path shall pump water from the Condensate Storage Tank to the steam generator(s) associated with the affected flow path; and the flow path availability will be verified by steam generator level change or Auxiliary Feedwater Safety Grade Flow Indication.

2. If the modification or repair is upstream of the test flow line, the auxiliary feed pump shall pump water through the Auxiliary Feedwater System to the test flow line; and the flow path availability will be verified by flow indication in the test flow line.*

This Surveillance Testing shall be performed prior to entering MODE 3 if the modification is made in MODES 4, 5 or 6. Verification of the Auxiliary Feedwater System's flow capacity is not required.

g. Following each extended cold shutdown (> 30 days in MODE 5), by:

1. Verifying that there is a flow path from each auxiliary feedwater pump to both steam generators by pumping Condensate Storage Tank water with each pump to both steam generators. The flow paths shall be verified by either steam generator level change or Auxiliary Feedwater Safety Grade Flow Indication. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3.

Verification of the Auxiliary Feedwater System's flow capacity is not required.

4.7.1.2.2 The Auxiliary Feed Pump Turbine Inlet Steam Pressure Interlocks shall be demonstrated OPERABLE when the steam line pressure is greater than 275 psig, by performance of a CHANNEL FUNCTIONAL TEST at least once per 31 days, and a CHANNEL CALIBRATION at least once each REFUELING INTERVAL ~~per 18 months~~. The CHANNEL FUNCTIONAL TEST shall be performed within 24 hours after exceeding 275 psig during each plant startup, if the test has not been performed within the last 31 days.

* When conducting tests of an auxiliary feedwater train in MODES 1, 2, and 3 which require local manual realignment of valves that make the train inoperable, the Motor Driven Feedwater Pump and its associated flow paths shall be OPERABLE per Specification 3.7.1.7 during the performance of this surveillance. If the Motor Driven Feedwater Pump or an associated flow path is inoperable, a dedicated individual shall be stationed at the realigned auxiliary feedwater train's valves (in communication with the control room) able to restore the valves to normal system OPERABLE status.

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inject water into the reactor coolant system is disabled to ensure operation within reactor coolant system pressure-temperature limits.

Demonstration of the safety valves' lift settings will occur only during shutdown and will be performed in accordance with the provisions of Section XI of the ASME Boiler and Pressure Code.

The pressurizer code safety valves must be set such that the peak Reactor Coolant System pressure does not exceed 110% of design system pressure (2500 psig) or, 2750 psig. The control rod group withdrawal accident will result in the most limiting high pressure in the RCS. The analysis assumes RPS high pressure trip at 2355 psig and the code safety valves open at 2500 psig. The tolerance on the RPS instrument accuracy is 30 psi and, it is +1% for the code safety valve settings. The pressurizer pilot operated relief valve was assumed not to open for this transient. The resulting system peak pressure was calculated to be 2700 psig. Therefore, the code safety valve setpoint is conservatively set at $\leq$ 2525 psig which is the maximum pressure of 2500 psig +1% for tolerance.

The pressurizer pilot operated relief valve should be set such that it will open before the code safety valves are opened. However, it should not open on any anticipated transients. BAW-1890, September 1985 identified that the turbine trip from full power would cause the largest overpressure transient. This report demonstrated that with a RPS high pressure trip setpoint of 2355 psig the resulting overshoot in RCS pressure would be limited to 50 psi. Consequently, the minimum PORV setpoint needs to accommodate both the RCS pressure overshoot and the RPS instrument string error of 30 psi.

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 and 3/4.3.2 REACTOR PROTECTION SYSTEM AND SAFETY SYSTEM INSTRUMENTATION

The OPERABILITY of the RPS, SFAS and SFRCS instrumentation systems ensure that 1) the associated action and/or trip will be initiated when the parameter monitored by each channel or combination thereof exceeds its setpoint, 2) the specified coincidence logic is maintained, 3) sufficient redundancy is maintained to permit a channel to be out of service for testing or maintenance, and 4) sufficient system functional capability is available for RPS, SFAS and SFRCS purposes from diverse parameters.

The OPERABILITY of these systems is required to provide the overall reliability, redundance 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.

For the RPS and SFRCS Table 4.3-11 Functional Unit 1.b:

Only the Allowable Value is specified for each Function. Nominal trip setpoints are specified in the setpoint analysis. The nominal trip setpoints are selected to ensure the setpoints measured by CHANNEL FUNCTIONAL TESTS do not exceed the Allowable Value if the bistable is performing as required. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable provided that operation and testing are consistent with the assumptions of the specific setpoint calculations. Each Allowable Value specified is more conservative than the analytical limit assumed in the safety analysis to account for instrument uncertainties appropriate to the trip parameter. These uncertainties are defined in the specific setpoint analysis.

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Setpoints must be found within the specified Allowable Values. Any setpoint adjustment shall be consistent with the assumptions of the current specific setpoint analysis.

A CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. The test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift to ensure that the instrument channel remains operational between successive tests. CHANNEL CALIBRATION shall find that measurement errors and bistable setpoint errors are within the assumptions of the setpoint analysis. CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the setpoint analysis.

The frequency is justified by the assumption of an 18 or 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

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3/4.3.1 and 3/4.3.2 REACTOR PROTECTION SYSTEM AND SAFETY SYSTEM INSTRUMENTATION (Continued)

The measurement of response time at the specified frequencies provides assurance that the RPS, SFAS, and SFRCS action function associated with each channel is completed within the time limit assumed in the safety analyses. No credit was taken in the analyses for those channels with response times indicated as not applicable.

Response time may be demonstrated by any series of sequential, overlapping or total channel test measurements provided that such test demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either 1) in place, onsite or offsite test measurements or 2) utilizing replacement sensors with certified response times.

The actuation logic for Functional Units 4.a., 4.b., and 4.c. of Table 3.3-3, Safety Features Actuation System Instrumentation, is designed to provide protection and actuation of a single train of safety features equipment, essential bus or emergency diesel generator. Collectively, Functional Units 4.a., 4.b., and 4.c. function to detect a degraded voltage condition on either of the two 4160 volt essential buses, shed connected loads, disconnect the affected bus(es) from the offsite power source and start the associated emergency diesel generator. In addition, if an SFAS actuation signal is present under these conditions, the sequencer channels for the two SFAS channels which actuate the train of safety features equipment powered by the affected bus will automatically sequence these loads onto the bus to prevent overloading of the emergency diesel generator. Functional Unit 4.a. has a total of four units, one associated with each SFAS channel (i.e., two for each essential bus). Functional Units 4.b. and 4.c. each have a total of four units, (two associated with each essential bus); each unit consisting of two undervoltage relays and an auxiliary relay.

An SFRCS channel consists of 1) the sensing device(s), 2) associated logic and output relays (including Isolation of Main Feedwater Non Essential Valves and Turbine Trip), and 3) power sources.

The SFRCS response time for the turbine stop valve closure is based on the combined response times of main steam line low pressure sensors, logic cabinet delay for main steam line low pressure signal s and closure time of the turbine stop valves. This SFRCS response time ensures that the auxiliary feedwater to the unaffected steam generator will not be isolated due to a SFRCS low pressure trip during a main steam line break accident.

Safety-grade anticipatory reactor trip is initiated by a turbine trip (above 45 percent of RATED THERMAL POWER) or trip of both main feedwater pump turbines. This anticipatory trip will operate in advance of the reactor coolant system high pressure reactor trip to reduce the peak reactor coolant system pressure and thus reduce challenges to the power operated relief valve. This anticipatory reactor trip system was installed to satisfy Item II.K.2.10 of NUREG-0737. The justification for the ARTS turbine trip arming level of 45% is give in BAW-1893, October, 1985.

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3/4.3.3 MONITORING INSTRUMENTATION

3/4.3.3.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring channels ensures that 1) the radiation levels are continually measured in the areas served by the individual channels and 2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded.

3/4.3.3.2 INCORE DETECTORS

The OPERABILITY of the incore detectors ensures that the measurements obtained from use of this system accurately represent the spatial neutron flux distribution of the reactor core. See Bases Figures 3-1 and 3-2 for examples of acceptable minimum incore detector arrangements.

3/4.3.3.3 SEISMIC INSTRUMENTATION

Deleted

3/4.3.3.4 METEOROLOGICAL INSTRUMENTATION

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3/4.3.3.5 REMOTE SHUTDOWN INSTRUMENTATION

The OPERABILITY of the remote shutdown instrumentation ensures that sufficient capability is available to permit shutdown and maintenance of

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REMOTE SHUTDOWN INSTRUMENTATION (Continued)

HOT STANDBY of the facility from locations outside of the control room. This capability is required in the event control room habitability is lost.

SR 4.3.3.5.2 verifies that each Remote Shutdown System transfer switch and control circuit required for a serious control room or cable spreading room fire performs its intended function. This verification is performed from the remote shutdown panel and locally, as appropriate. This will ensure that if the control room becomes inaccessible, the unit can be safely shutdown from the remote shutdown panel and the local control stations.

3/4.3.3.6 POST-ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the post-accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. The containment Hydrogen Analyzers, although they are considered part of the plant post-accident monitoring instrumentation, have their OPERABILITY requirements located in Specification 3/4.6.4.1, Hydrogen Analyzers.

3/4.3.3.7 CHLORINE DETECTION SYSTEMS - Deleted

3/4.3.3.8 FIRE DETECTION INSTRUMENTATION - Deleted

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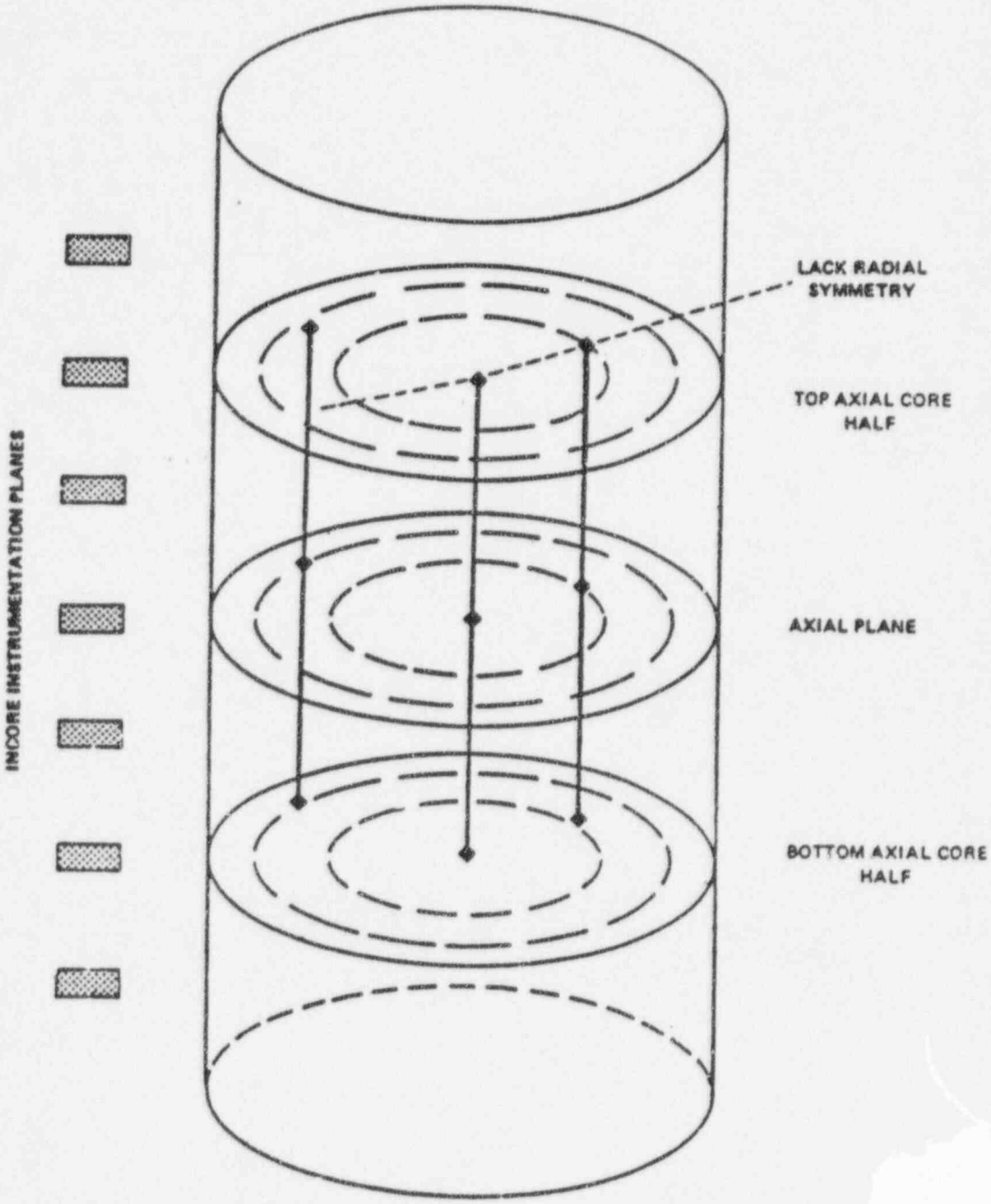

Bases Figure 3-1 Incore Instrumentation Specification
Acceptable Minimum AXIAL POWER IMBALANCE Arrangement

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3/4.4.1 REACTOR COOLANT LOOPS

The plant is designed to operate with both reactor coolant loops in operation, and maintain DNBR above the minimum allowable DNB ratio during all normal operations and anticipated transients. With one reactor coolant pump not in operation in one loop, THERMAL POWER is restricted by the Nuclear Overpower Based on RCS Flow and AXIAL POWER IMBALANCE, ensuring that the DNBR will be maintained above the minimum allowable DNB ratio at the maximum possible THERMAL POWER for the number of reactor coolant pumps in operation or the local quality at the point of minimum DNBR equal to the DNB correlation quality limit, whichever is more restrictive.

In MODE 3 when RCS pressure or temperature is higher than the decay heat removal system's design condition (i.e. 330 psig and 350°F), a single reactor coolant loop provides sufficient heat removal capability. The remainder of MODE 3 as well as in MODES 4 and 5 either a single reactor coolant loop or a DHR loop will be sufficient for decay heat removal; but single failure considerations require that at least two loops be OPERABLE. Thus, if the reactor coolant loops are not OPERABLE, this specification requires two DHR loops to be OPERABLE.

Natural circulation flow or the operation of one DHR pump provides adequate flow to ensure mixing, prevent stratification and produce gradual reactivity changes during boron concentration reductions in the Reactor Coolant System. The reactivity change rate associated with boron reduction will, therefore, be within the capacity of operator recognition and control.

3/4.4.2 and 3/4.4.3 SAFETY VALVES

The pressurizer code safety valves operate to prevent the RCS from being pressurized above its Safety Limit of 2750 psig. Each safety valve is designed to relieve 336,000 lbs per hour of saturated steam at the valve's setpoint.

The relief capacity of a single safety valve is adequate to relieve any overpressure condition which could occur during shutdown. In the event that no safety valves are OPERABLE, an operating DHR loop, connected to the RCS, provides overpressure relief capability and will prevent RCS overpressurization. During operation, all pressurizer code safety valves must be OPERABLE to prevent the RCS from being pressurized above its safety limit of 2750 psig. The combined relief capacity of all of these valves is greater than the maximum surge rate resulting from any transient.

The relief capacity of the decay heat removal system relief valve is adequate to relieve any overpressure condition which could occur during shutdown. In the event that this relief valve is not OPERABLE, reactor coolant system pressure, pressurizer level and make up water inventory is limited and the capability of the high pressure injection system to

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3/4.4.6 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.6.1 LEAKAGE DETECTION SYSTEMS

The RCS leakage detection systems required by this specification are provided to detect and monitor leakage from the Reactor Coolant Pressure Boundary. These detection systems are consistent with the recommendation of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.

3/4.4.6.2 OPERATIONAL LEAKAGE

PRESSURE BOUNDARY LEAKAGE of any magnitude is unacceptable since it may be indicative of an impending gross failure of the pressure boundary. Therefore, the presence of any PRESSURE BOUNDARY LEAKAGE requires the unit to be promptly placed in COLD SHUTDOWN.

Industry experience has shown that, while a limited amount of leakage is expected from the RCS, the UNIDENTIFIED LEAKAGE portion of this can be reduced to a threshold value of less than 1 GPM. This threshold value is sufficiently low to ensure early detection of additional leakage.

The total steam generator tube leakage limit of 1 GPM for all steam generators ensures that the dosage contribution from tube leakage will be limited to a small fraction of 10 CFR Part 100 limits in the event of either a steam generator tube rupture or steam line break. The 1 GPM limit is consistent with the assumptions used in the analysis of these accidents.

The 10 GPM IDENTIFIED LEAKAGE limitation provides allowance for a limited amount of leakage from known sources whose presence will not interfere with the detection of UNIDENTIFIED LEAKAGE by the leakage detection systems.

The CONTROLLED LEAKAGE limit of 10 GPM restricts operation with a total RCS leakage from all RC pump seals in excess of 10 GPM.

The surveillance requirements for RCS Pressure Isolation Valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS Pressure Isolation Valves is IDENTIFIED LEAKAGE and will be considered as a portion of the allowed limit.

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3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM

The OPERABILITY of the Auxiliary Feedwater System ensures that the Reactor Coolant System can be cooled down to less than 280°F from normal operating conditions in the event of a total loss of offsite power. The OPERABILITY of the Auxiliary Feed Pump Turbine Inlet Steam Pressure Interlocks is required only for high energy line break concerns and does not affect Auxiliary Feedwater System OPERABILITY.

The Condensate Storage Tanks are the non-safety-related primary source of the water for the Auxiliary Feedwater System. When the auxiliary feedwater pumps are needed and either the Condensate Storage Tanks are not available or have been emptied by the Auxiliary Feedwater System, a safety-related transfer system transfers the suction from the Condensate Storage Tanks to the Service Water System. The Service Water System is the safety-related secondary source of the water and must be available for the associated Auxiliary Feedwater System train to be OPERABLE. The transfer is initiated upon detection of a low suction pressure at the suction of the auxiliary feedwater pumps by suction pressure interlock switches. These pressure switches, upon sensing low suction pressure, will automatically transfer the suction of the auxiliary feedwater pumps to the Service Water System. On a sustained low-low suction pressure, additional Auxiliary Feedwater Pump Suction Pressure Interlocks will operate to close the steam supply valves to protect the turbine driven auxiliary feedwater pumps from cavitation. The steam supply valves will re-open automatically upon restoration of suction pressure to the pumps. Both the low and the low-low suction Auxiliary Feed Pump Suction Pressure Interlocks are required to be OPERABLE for OPERABILITY of the associated auxiliary feedwater train.

Each steam driven auxiliary feedwater pump is capable of delivering the required feedwater flow at the full open pressure of the Main Steam Safety Valves as assumed in the Updated Safety Analysis Report. This capacity is sufficient to ensure that adequate feedwater flow is available to remove decay heat and reduce the Reactor Coolant System temperature to less than 280°F where the Decay Heat Removal System may be placed in operation. Each train of auxiliary feedwater must be capable of providing feedwater flow to each steam generator in order to be OPERABLE. However, the design of the system does not provide for feeding both steam generators simultaneously from one train.

When conducting tests of an auxiliary feedwater train in MODES 1, 2, or 3 which require local manual realignment of valves that make the train inoperable, a dedicated individual shall be stationed at the valves, in communication with the control room, able to restore the valves to normal system OPERABLE status. However, it is not required to have this dedicated individual stationed if the other train of the Auxiliary Feedwater System is OPERABLE and the Motor Driven Feedwater Pump System is OPERABLE pursuant to Technical Specification 3/4.7.1.7 because two sources of auxiliary feedwater to the steam generators are OPERABLE. In either situation, the Auxiliary Feedwater System train with the local manual realigned valves is inoperable and the Limiting Condition for Operation ACTION must be followed.

Closure of valve AF 599 or AF 608 will render both trains of the Auxiliary Feedwater System and the Motor Driven Feedwater Pump System inoperable. This is because closure of these valves would result in a complete loss of auxiliary feedwater to the steam generators for certain postulated feedwater line and steam line breaks.

(3/4.7.1.2 is continued on page B 3/4 7-2.)

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3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM (Continued)

Following any modifications or repairs to the Auxiliary Feedwater System piping from the Condensate Storage Tank through auxiliary feed pumps to the steam generators that could affect the system's capability to deliver water to the steam generators, following extended cold shutdown, a flow path verification test shall be performed. This test may be conducted in MODES 4, 5 or 6 using auxiliary steam to drive the auxiliary feed pumps turbine to demonstrate that the flow path exists from the Condensate Storage Tank to the steam generators via auxiliary feed pumps.

Verification of the turbine plant cooling water valves (CW 196 and CW 197), the startup feedwater pump suction valves (FW 32 and FW 91), and the startup feedwater pump discharge valve (FW 106) in the closed position is required to address the concerns associated with potential pipe failures in the auxiliary feedwater pump rooms, that could occur during operation of the startup feedwater pump.

3/4.7.1.3 CONDENSATE STORAGE TANKS

The OPERABILITY of the Condensate Storage Tanks with the minimum water volume ensures that sufficient water is available to maintain the RCS at HOT STANDBY conditions for 13 hours with steam discharge to atmosphere and to cooldown the Reactor Coolant System to less than 280° under normal conditions (i.e., no loss of offsite power). The contained water volume limit includes an allowance for water not usable because of tank discharge line location or other physical characteristics.

3/4.7.1.4 ACTIVITY

The limitations on secondary system specific activity ensure that the resultant offsite radiation dose will be limited to a small fraction of 10 CFR Part 100 limits in the event of a steam line rupture. This dose includes the effects of a coincident 1.0 GPM primary to secondary tube leak in the steam generator of the affected steam line. These values are consistent with the assumptions used in the safety analyses.

3/4.7.1.5 MAIN STEAM LINE ISOLATION VALVES

The OPERABILITY of the main steam line isolation valves ensures that no more than one steam generator will blowdown in the event of a steam line rupture. This restriction is required to 1) minimize the positive reactivity effects of the Reactor Coolant System cooldown associated with the blowdown, and 2) limit the pressure rise within containment in the event the steam line rupture occurs within containment. The OPERABILITY of the main steam isolation valves

Summary of Licensing Basis, Surveillance Data, and Maintenance Records Review for Technical Specification 2.2 and Surveillance Requirement 4.3.1.1.1

1. A. Technical Specification (TS): 2.2, "Limiting Safety System Settings," Table 2.2-1, "Reactor Protection System Instrumentation Trip Setpoints

   3/4.3.1, "Reactor Protection System Instrumentation"

   Surveillance Requirement (SR) 4.3.1.1.1, Table 4.3-1, Functional Units 3 through 7 and Functional Unit 14, Channel Calibrations.

   Note: Functional Units 1, 2, 8, 12, 13 do not require a revision to current surveillance intervals to support a 24 month fuel cycle. Channel Calibrations for Functional Units 9, 10, and 11 are proposed to remain on a 18 month surveillance interval and the Channel Functional Test for Functional Unit 15 is proposed to be increased to 24 months as discussed in License Amendment Request LAR 95-0027 (DBNPS letter Serial Number 2405).

   B. System Affected

   Reactor Protection System Instrumentation

   C. USAR Sections:

3D.1.6	Criterion 10 - Reactor Design
3D.1.8	Criterion 12 - Suppression of Reactor Power Oscillations
3D.1.9	Criterion 13 - Instrumentation and Control
3D.1.16	Criterion 20 - Protection System Functions
3D.1.17	Criterion 21 - Protection System Reliability and Testability
4.3	Nuclear Design
5.2	Integrity of Reactor Coolant Pressure Boundary
7.2	Reactor Protection System
7.4	Systems Required for Safe Shutdown
7.7	Control Systems

2. Licensing Basis Review:

   A. Technical Specification 4.3.1.1.1 requires that a Channel Calibration be performed every 18 months on each Reactor Protection System (RPS) channel for the following Functional Units: Reactor (RC) Coolant High Temperature (Unit 3); RC Low Pressure (Unit 5); RC High Pressure (Unit 6); RC Pressure-Temperature (Unit 7); and Shutdown Bypass High Pressure (Unit 14). Functional Unit 4,

Flux-ΔFlux-Flow, footnote 7 requires that each associated flow measurement sensor is calibrated at least once per 18 months. Technical Specification 4.0.2 is applicable which allows increasing the surveillance interval on a non-routine basis from 18 months to 22.5 months.

It is proposed that a new definition for the "R" notation of be applied in Technical Specification Table 4.3-1, for Functional Units 3, 5 through 7 and 14. In License Amendment Request 95-0027 (DBNPS letter Serial Number 2405) it is proposed that the "R" notation be defined as "As least once per 24 months." Further, it is proposed that in footnote 7 for functional unit 4, the words "at least once per 18 months" be replaced with "at least once each REFUELING INTERVAL." License Amendment Request 95-0018 (DBNPS letter Serial Number 2342) proposes that "REFUELING INTERVAL" be defined as "A period of time ≤ 730 days."

This is consistent with the guidance provided in Generic Letter 91-04. Technical Specification 4.0.2 would continue to apply which would allow increasing the new surveillance interval on a non-routine basis from 24 months to 30 months.

As shown on the attached marked-up Technical Specification pages, Technical Specification Table 2.2-1, Reactor Protection System Instrumentation Trip Setpoints, is proposed for revision by deletion of the Trip Setpoints associated column heading and column, and to reflect that the existing Allowable Values are applicable to the Channel Functional Test, by application of the "*," footnote in Table 2.2-1 and deletion of the "**," and "#" footnotes to the table. For Functional Unit 5, RC low pressure, and Functional Unit 6, RC high Pressure, the Allowable Values applicable to the Channel Calibration, "≥ 1900.0 psig**," and "≤ 2355.0 psig**," respectively, are proposed for deletion.

Application of the existing Allowable Values to the Channel Functional Test was determined by incorporation of the instrument drift study results by Framatome into the "Reactor Protection System String Error Calculations" (document 32-1172392-02, dated July 26, 1996) and the "DBNPS Unit 1 RPS Setpoint Allowable Values Calculation" (document 32-1257719-02, dated September 25, 1996).

The Limiting Condition for Operation for TS 2.2, Limiting Safety System Settings, is proposed for revision, as shown on the attached marked-up Technical Specification pages, to reflect the proposed revisions to TS Table 2.2-1. Technical Specification Bases 2.1, Limiting Safety System Settings, and TS Bases 3/4.3.1 and 3/4.3.2, Reactor Protection System and Safety System Instrumentation, are also proposed for revision to reflect the proposed revisions to TS 2.2 and Table 2.2-1.

These changes are consistent with NUREG-1430, "Standard Technical Specifications, Babcock and Wilcox Plants," dated April, 1995.

Further, it is proposed that the RPS High Flux Trip Allowable Value, Functional Unit 2, in Table 2.2-1, "Reactor Protection System Instrumentation Trip Setpoints," be increased from 104.94% of rated power to 105.1% of rated power. This change is not a result of the instrument drift study for conversion to a 24 month fuel cycle but rather is due to a change in the way the bistable error was determined. Previously, the individual error terms were simply added together to obtain the total bistable error. These errors terms have now been separated into random and correlated categories. The random errors were combined using the square-root-sum-of-the-squares method and the correlated errors were added together. The random and correlated errors were then added together to yield the total bistable error. Also, the error terms that are manifested in the results of the on-line channel functional test were not included in the determination of the bistable error for the purpose of calculating the Allowable Value. Those error terms are accounted for in the field setpoint calculation. This is consistent with ISA S67.04, Part I-1994, "Setpoints for Nuclear Safety-Related Instrumentation." This results in a lower bistable error and, therefore, a slightly higher Allowable Value.

As shown on the attached marked-up Technical Specification pages, Technical Specification Bases 2.1, Limiting Safety System Settings, is proposed for revision to reflect the proposed change to the High Flux Allowable Value.

B. The purpose of the RPS is to initiate a reactor trip when a sensed parameter (or group of parameters) exceeds a setpoint value indicating the approach of an unsafe condition. In this manner, the reactor core is protected from exceeding design and safety limits and the Reactor Coolant System (RCS) is protected from overpressurization. the rps monitors the following generating station variables:

1. Total out-of-core neutron flux
2. RCS coolant flow
3. RCS pump status
4. RCS reactor outlet temperature
5. RCS pressure
6. Containment Vessel pressure
7. Out-of-core neutron flux imbalances

The RPS is described in the DBNPS Updated Safety Analysis Report (USAR), Section 7.2. The RPS consists of four identical protection channels which are redundant and independent. Each channel is served by its own independent sensors which are physically isolated from the sensors of the other protective channels. Each sensor supplies an input signal to one or more signal processing strings in the RPS channel. Each signal processing string terminates in a bistable which electronically compares the processed signal with trip setpoints. All bistable contacts are connected in series.

The trip functions of each RPS channel are as follows:

1. High RC Pressure - Each RPS channel receives signals from a separate narrow-range RC pressure transmitter. Each pressure transmitter is powered from its own power supply, which is packaged in a module and mounted in the associated RPS channel cabinet. The output of each pressure transmitter is applied directly to the input of a buffer amplifier. The buffer amplifier module consists of an input stage amplifier driving a primary output amplifier and up to nine additional output amplifiers. The primary output amplifier supplies the signal to the RPS pressure bistables. The high RC pressure bistable module compares this input signal to an internal trip setpoint power supply. When the input signal from the buffer amplifier exceeds the setpoint of the bistable, its relay contact will open and de-energize (trip) the channel terminating relay.

2. Low RC Pressure - The same pressure transmitter and buffer amplifier described above supplies a signal to the low RC pressure bistable. When this input signal decreases below a preset setpoint of the bistable, its relay contact will open and de-energize (trip) the channel terminating relay.

3. High RC Temperature Trip - Each RPS channel receives reactor outlet temperature signals from a separate resistance temperature element. The element is supplied with a matched resistance bridge unit that is mounted in the associated RPS channel cabinet. The linear bridge produces an analog output that is fed to the signal converter which conditions the signal and produces two prime outputs. One output signal is supplied to the variable low RC pressure bistable. The other output is applied to the high RC temperature trip bistable. When the input temperature signal from the signal converter exceeds the trip setpoint of the high RC temperature bistable, its relay contact will open and de-energize (trip) the channel terminating relay.

4. Variable Low RC Pressure - A pressure signal is sent to the pressure/temperature bistable from the same primary output amplifier of the buffer amplifier that supplies the high and low RC pressure bistables. This signal is compared to the pressure setpoint generated as a function of the temperature input to the signal converter described in (3) above. When the pressure signal is outside the allowable bounds, the pressure/temperature bistable will trip, opening its relay contact and de-energizing (tripping) the channel terminating relay. This trip is represented by the slope of the pressure-temperature envelope contained in the Technical Specifications.

5. Overpower - Each RPS channel contains a two-section power range neutron flux detector. The signals from each half are summed to produce a total power signal. This power signal is sent to the overpower, power/pumps, and power/imbalance/flow bistables. When the total power signal exceeds the overpower trip setpoint of the bistable, its relay contact will open, de-energizing (tripping) the channel terminating relay.

6. Power/Pumps - RC pump status (on-off) and information as to the loops in which pumps are operating, is monitored by pump monitors. The pump monitors provide an open or closed contact as the input to the RPS. The pump contact monitor module provides a variable signal which is a function of the number of running pumps and the loop in which they are running. This signal is used as a variable setpoint signal in the power/pumps bistable. If the total reactor power exceeds the power/pumps setpoint, as determined by the pump configuration, the bistable will cause its associated relay contact to open, de-energizing (tripping) the channel terminating relay.

7. Power/Imbalance/Flow - Each RPS channel receives two differential pressure signals (one from each reactor coolant loop). The signals are developed by differential pressure transmitters that measure pressure drop across gentile tubes mounted in the two reactor coolant loops. The analog output of the transmitters is proportional to flow squared. The square root extractor converts the signal to one directly proportional to flow. The proportional flow signals from both RC loops are summed to produce a total RC flow signal in the summing amplifier.

   Each RPS channel monitors reactor power imbalance. This is the difference between the power measured in the top half of the core and the power measured in the bottom half of the core by the two separate power range neutron flux detectors.

   The imbalance signal and the flow signal are combined in a Function Generator and the resultant function signal is compared with the total power signal in a bistable. The bistable will trip when the total reactor power signal exceeds the trip envelope limit in the Core Operating Limits Report. When this bistable trips, its relay contact opens, de-energizing (tripping) the channel terminating relay.

8. High CV Pressure - Each RPS channel monitors CV pressure by means of a pressure switch. If the CV pressure setpoint is exceeded, the pressure switch will open causing the high CV pressure contact buffer to open its contact. This will de-energize (trip) the channel terminating relay.

A shutdown bypass is provided to allow rod withdrawal testing with the unit shutdown. To initiate the bypass the operator must turn a key switch in each RPS channel. Turning the key switch removes the following trips from the logic train: power/imbalance/flow, power/pumps, variable low RC pressure, and low RC pressure. The key switch also inserts the shutdown bypass high pressure trip. The setpoint of this trip is lower than the setpoint of the normal low pressure trip. During normal operation the shutdown bypass high pressure trip bistable is normally tripped since operating pressure is greater than the trip setpoint. If the operator initiates the shutdown bypass with the unit at power that RPS channel trips.

The RPS channel bypass permits the testing and maintenance of a single channel during power operations. With the bypass in effect, the three remaining channels provide the necessary protection. Since only two channel trips are required to cause a reactor trip, a single failure will not prevent the RPS from fulfilling its protective function.

In the normal untripped state, the contact associated with each bistable will be closed, thereby energizing the channel terminating relay. A trip of one of the channel bistables in one channel causes a half trip in each of the four RPS channels. The trip of a bistable in a second channel completes the two-out-of-four logic and causes a full trip of each RPS channel. The full trip of each channel deenergizes the undervoltage coils and undervoltage relays of the channel's respective Control Rod Drive (CRD) trip breaker in the Control Rod Drive Control System (CRDCS). Each RPS channel contains a reactor trip module which performs the two-out-of-four trip logic and provides the signals to open the channels' associated CRD trip breaker.

The RPS is a de-energize-to-trip system. Therefore, if power is lost to a channel, that channel will trip, reducing the system trip coincidence to one-out-of-three. In the event that a module, which performs a protective function is removed from its rack, that RPS channel will trip (unless that channel is bypassed).

The RPS is not an initiator, nor contributor, to the initiation of an accident described in the USAR. The design purpose of the RPS is to initiate a reactor trip when a sensed parameter or group of parameters exceeds a setpoint value indicating the approach of an unsafe condition and thereby protecting the reactor core from exceeding design limits and the RCS from overpressurization. The trip setpoints are selected so that no core design limits are exceeded as a consequence of any anticipated

operational occurrences. Further, the shutdown bypass is utilized when the unit is in a shutdown condition and initiation of the shutdown bypass while at power would cause a trip of the effected RPS channel. The RPS is designed so that no single failure can prevent the RPS from performing its protective function.

C. The 18 month surveillance frequency for the channel calibration was identified in the original operating license and technical specifications issued for the DBNPS, dated April 22, 1977, for Reactor Coolant High Temperature, Flux-ΔFlux-Flow, and the Shutdown Bypass High Pressure Functional Units, consistent with NUREG-0103, "Standard Technical Specifications for Babcock and Wilcox Pressurized water Reactors," Revision 0, dated June 1, 1976.

As required by NUREG-0136, "Safety Evaluation Report for The Davis-Besse Nuclear Power Station, Unit 1," dated December 1976, Section 7.2, the surveillance interval was reduced to four months from 18 months for the Reactor Coolant Low Pressure, Reactor Coolant High Pressure and Reactor Coolant Pressure Temperature Functional Units, due to the excessive drift of the reactor coolant pressure transmitters. The four month surveillance interval was changed to 18 months by Amendment No. 7 to Facility Operating License No. NPF-3 for the Davis-Besse Nuclear Power Station, Unit No. 1, dated November 29, 1977, as a result of replacing the reactor coolant pressure transmitters.

As discussed above the proposed changes follow the guidance of Generic Letter 91-04.

D. As a result of the above review, it is concluded that the licensing basis of the Reactor Protection System will not be invalidated by increasing the surveillance interval for Technical Specification 4.3.1.1.1 , Table 4.3-1 Items 3, 5 through 7, Item 14 and Item 4 Footnote 7, Channel Calibrations from 18 months to 24 months and by continuing to allow application of Technical Specification 4.0.2 on a non-routine basis.

E. References

i. Davis-Besse Nuclear Power Station (DBNPS) Unit No. 1, Operating License NPF-3, Appendix A, Technical Specifications, through Amendment 212.

ii. Generic Letter 91-04, "Changes in Technical Specifications Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991.

iii. "Standard Technical Specifications for Babcock and Wilcox Pressurized Water Reactors," NUREG-0103, Revision 0, dated June 1, 1976.

iv. NUREG-0136, Safety Evaluation Report for The Davis-Besse Nuclear Power Station, Unit 1, dated December 1976 and Supplement No. 1.

v. Amendment No. 7 to Facility Operating License No. NPF-3 for the Davis-Besse Nuclear Power Station, Unit No. 1, dated November 29, 1977.

vi. NUREG-1430, "Standard Technical Specifications, Babcock and Wilcox Plants," dated April, 1995.

vii. Framatome document 32-1172392-02, "Reactor Protection System String Error Calculations," dated July 26, 1996.

viii. Framatome document 32-1257719-02, "DBNPS Unit 1 RPS Setpoint Allowable Values Calculation," dated September 25, 1996.

ix. ISA S67.04, Part I-1994, "Setpoints for Nuclear Safety-Related Instrumentation."

3. Instrument Drift Study Analysis

A. Enclosure 2 of Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Support a 24-Month Fuel Cycle," dated April 2, 1991, identifies seven issues to be addressed in justifying increased surveillance intervals to accommodate a 24 month fuel cycle.

The following sections address, by number, the first six of seven issues, specified in Enclosure 2 of Generic Letter 91-04, necessary to justify a cycle extension from 18 to 24 months. The seventh issue is discussed in the main body of this license amendment application.

Reactor Coolant Temperature

(TERC3A2, TERC3A4, TERC3B2, TERC3B4)

1. RTDs - Drift could not be determined by analyzing as-found and as-left calibration data because RTDs are not calibrated by applying a measured input, measuring the output, and making adjustments if necessary. Instead, they are tested using the cross calibration method. The test's acceptance criteria for RPS RTDs is ±0.5 °F. The maximum deviation determined for an RPS RTD during any test data run was 0.427 °F, which is within acceptable limits. For data taken above 520 °F (i.e., within the range of the signal processing modules and bistables), the worst case deviation was only 0.266 °F, slightly over half the acceptance limit. These results, therefore, have not exceeded acceptable limits.

Linear Bridge modules - Historical drift values could not be directly compared with a corresponding design basis/reference uncertainty. Reasonable assurance that historical drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval was obtained by considering that the worst case drift recorded is as small as the most limiting of the three calibration tolerances used and is less than half the value that

was used in the RPS string error calculation for the drift of the RTD/linear bridge combination. Also, during the sixth through ninth refueling outages, the channel functional tests performed for the RPS RC high temperature trip as part of the refueling channel calibrations measured the temperature signal at the linear bridge module input, thereby including the effect of its drift in the test results. There were no instances of these test results exceeding the Allowable Value.

2. RTDs - This issue is not applicable to the RTDs (reference discussion in issue 1).

   Linear Bridge modules - Data was taken at 0%, 50%, and 100% of span. For all three points, the 95/95% tolerance interval was ±0.04% of span.

3. RTDs - Since RTDs are not adjusted between tests, the results discussed under issue 1 above provide sufficient evidence to reasonably conclude that the RPS RTDs will continue to meet the ±0.5 °F acceptance criteria if cross calibration testing is performed at 24 month intervals.

   Linear Bridge modules - The assertion that drift is independent of time could be supported, however, since there were numerous instances on the drift versus time since last adjustment plots of data falling outside the 95/95% tolerance interval of ±0.04% of span, the 30 month projected drift was chosen to be ±0.10% of span. This is conservative, as it encompasses all the data on the drift versus time since last adjustment plots.

4. The design basis/reference uncertainty could not be directly determined for comparison with the drift study results because the RPS string error calculation treated the RTD and linear bridge as a single component for the purpose of uncertainty calculations. In other words, separate reference accuracy and drift terms were not used for the RTD and the linear bridge, rather a single reference accuracy was used for the RTD/linear bridge combination, and the same holds true for drift. Therefore, the RPS string error calculation was revised to separate the uncertainty terms as necessary to support direct use of the drift study results. Allowable Values for the RPS RC high temperature and pressure-temperature trips were recalculated, and both encompass the present limits, therefore no Allowable Value changes are being proposed for these trips.

5. The RPS instrumentation within the scope of these Technicla Specification requirements does not control any plant parameters, but provides protective action signals to initiate a reactor trip when a sensed parameter (or group of parameters)exceeds a setpoint value indicating the approach of an unsafe condition. Therefore, this issue regarding control systems is not applicable.

6. The applicable surveillance and periodic test procedures were reviewed and verified to appropriately reflect all applicable conditions and assumptions of the setpoint and safety analyses.

Reactor Coolant Flow

(FTRC1A1, FTRC1A2, FTRC1A3, FTRC1A4, FTRC1B1, FTRC1B2, FTRC1B3, FTRC1B4)

1. Differential Pressure Transmitters - Historical drift exceeded its design basis/reference uncertainty (see discussion under issue 4 below) in the non-conservative direction during five of the 22 calibrations for which data was available and in the conservative direction during five other calibrations. This suggested that the design basis value for drift was not large enough to adequately characterize transmitter performance.

   Potential Condition Adverse to Quality Report 96-0278 was initiated to address this condition and resulted in appropriate corrective actions. Of the ten cases where historical drift exceeded the design basis/reference uncertainty, none would have exceeded the 30 month projected drift. Furthermore, only one of the extrapolated drift data points exceeds the 30 month projected drift, and that in the conservative direction. Therefore, now that the 30 month projected drift has been incorporated into the RPS string error calculation, it can reasonably be expected that differential pressure transmitter drift will rarely exceed acceptable limits.

   I/E Converters - Historical drift did not exceed its design basis/reference uncertainty (see discussion under issue 4 below) in any of the 27 calibrations for which data was reviewed.

2. Differential Pressure Transmitters - For all seven test points, the sample mean was less than 0.02% of span, which was considered to effectively be zero. The worst case 95/95% tolerance factor times sample standard deviation was 0.95% of span (random error). A one-sided tolerance factor was used because the RPS flux-Dflux -flow trip occurs on a decreasing flow signal, so its uncertainty is of concern only if measured flow exceeds actual flow.

   I/E Converters - For all nine test points, the sample mean was less than 0.02% of span, which was considered to effectively be zero. Therefore, the entire error was considered random. The worst case 95/95% tolerance interval maximum was 0.15% of span. A one-sided tolerance factor was used for the same reason as in the differential pressure transmitter case.

3. Differential Pressure Transmitters - Since there was no strong evidence to support a conclusion of drift time dependency, but merely insufficient evidence to clearly demonstrate a lack of time dependency, the drift versus time since last test data was extrapolated to a 30 month interval using the square root method described in the "Instrument Drift Data Analysis

Methodology and Assumptions" for DBNPS. For the extrapolated data, the sample mean was slightly negative but close to zero. Since negative drift is conservative for these differential pressure transmitters, and because the magnitude is small, the mean was considered zero. The worst case 95/95% tolerance factor times sample standard deviation was 1.34% of span (random error).

I/E Converters - It was concluded that drift is independent of time, therefore the 95/95% tolerance interval for 30 months is ±0.15% of span, as stated in the discussion under issue 2 above.

4. The design basis/reference uncertainty was obtained from the RPS string error calculation, which listed the differential pressure transmitter's accuracy as 0.25% of span (random error) and its drift as 0.25% of span (random error). It also listed the I/E converter's accuracy as 0.25% of span (random error). Combining the transmitter's two random terms using the square-root-sum-of--squares technique resulted in an overall random error of 0.35% of span. Comparing these errors with the transmitter's 30 month projected drift of 1.34% of span revealed that the design basis/reference uncertainty did not bound the 30 month projected drift. Therefore, even though the converter's design basis/reference uncertainty bounded its 30 month projected drift, the RPS string error calculation was revised to incorporate the 30 month projected drift determined for the differential pressure transmitter and for the I/E converter. The Allowable Value curve for the RPS Flux-ΔFlux-Flow trip was recalculated, and it is more restrictive than the previously calculated Cycle 11 limits but less restrictive than the presently utilized Cycle 9 limits. The Core Operating Limits Report will be revised to reflect these newly recalculated limits.

5. The RPS instrumentation within the scope of these Technical Specification requirements does not control any plant parameters, but provides protective action signals to initiate a reactor trip when a sensed parameter (or group of parameters) exceeds a setpoint value indicating the approach of an unsafe condition. Therefore, this issue regarding control systems is not applicable.

6. The applicable surveillance and periodic test procedures were reviewed and verified to appropriately reflect all conditions and assumptions of the setpoint and safety analyses.

Reactor Coolant Pressure

(PTRC2A1, PTRC2A2, PTRC2B1, PTRC2B2)

1. Pressure Transmitters - Historical drift exceeded the design basis/reference uncertainty (see discussion under issue 4 below) during six of the 37 calibrations for which data was available. Also, during the eighth refueling outage, the channel functional test performed for the RPS channel 1 Reactor Coolant High Pressure trip as part of the refueling channel calibration

resulted in a trip slightly above the Allowable Value. The field setpoints for the RPS Reactor Coolant Low Pressure, High Pressure, Pressure-Temperature, and Shutdown Bypass High Pressure trip functions were all made more conservative as corrective action for that event, and no further violations of Allowable Values have occurred. In addition, of the six cases where historical drift exceeded the design basis/reference uncertainty, none would have exceeded the 30 month projected drift. Furthermore, none of the extrapolated drift data points exceed the 30 month projected drift. Therefore, now that the 30 month projected drift has been incorporated into the RPS string error calculation, it can reasonably be expected that drift will rarely exceed acceptable limits.

2. Pressure Transmitters - Data was taken at 23 different test points throughout the 1700 to 2500 psig range. In order to make the data manageable, nine points at equal intervals were selected to characterize performance. This necessitated data column shifting, as described in the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS. Among the nine test points, the worst case sample mean was 0.14% of span (correlated error), and the worst case 95/95% tolerance factor times sample standard deviation was 0.94% of span (random error).

3. Pressure Transmitters - Since there was no strong evidence to support a conclusion of drift time dependency, but merely insufficient evidence to clearly demonstrate a lack of time dependency, the drift versus time since last test data was extrapolated to a 30 month interval using the square root method described in the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS. For the extrapolated data, the worst case sample mean was 0.25% of span (correlated error), and the worst case 95/95% tolerance factor times sample standard deviation was 1.24% of span (random error).

4. The design basis/reference uncertainty was obtained from the RPS string error calculation, which listed the pressure transmitter's reference accuracy as 0.25% of span (random error) and its drift as 0.6% of span (random error) and -0.075% of span (correlated error). Combining the two random terms using the square-root-sum--of-the-squares technique resulted in an overall random error of 0.65% of span. Comparing these errors with the 30 month projected drift of 0.25 ±1.24% of span revealed that the design basis/reference uncertainty did not bound the 30 month projected drift. Therefore, the RPS string error calculation was revised to incorporate the 30 month projected drift determined for the pressure transmitter. Allowable Values for the RPS RC Low Pressure, High Pressure, Pressure-Temperature, and Shutdown Bypass High Pressure trips were recalculated, and they either encompass or are the same as the present limits, therefore no Allowable Value changes are being proposed for these trips.

5. The RPS instrumentation within the scope of these Technical Specification requirements does not control any plant parameters,

but provides protective action signals to initiate a reactor trip when a sensed parameter (or group of parameters) exceeds a setpoint value indicating the approach of an unsafe condition.

Therefore, this issue regarding control systems is not applicable.

6. The applicable surveillance and periodic test procedures were reviewed and verified to appropriately reflect all conditions and assumptions of the setpoint and safety analyses.

Summary of Licensing Basis, Surveillance Data, and Maintenance Records Review for Technical Specification 3.3.2.2 and Surveillance Requirement 4.3.2.2.1

1. A. Technical Specification (TS): 3.3.2.2, "Steam and Feedwater Rupture Control System Instrumentation"

   Surveillance Requirement (SR) 4.3.2.2.1, Table 4.3-11, Functional Unit 1.b, Channel Calibration

   Note: the Channel Calibrations for Functional Units 1.a, 1.c, and 1.d are proposed to remain on a 18 month surveillance interval and the Channel Functional Test for Functional Unit 2 is proposed to be increased to 24 months as discussed in License Amendment Request 95-0027 (DBNPS letter Serial Number 2405).

   B. System Affected:

   Steam and Feedwater Rupture Control

   C. USAR Sections:

   5.5.1.3 RCP's Evaluation
   7.4.1.3 SFRCS
   10.3.3 Accident Analysis
   15.2.8 Loss of Normal Feedwater

2. Licensing Basis Review:

   A. Technical Specification 4.3.2.2.1 requires that a Channel Calibration be performed every 18 months in accordance with Table 4.3-11, Steam and Feedwater Rupture Control System Instrumentation Surveillance Requirements for Functional Unit 1.b Steam Generator Level - Low.

   Technical Specification 4.0.2 is applicable which allows increasing the surveillance interval on a non-routine basis from 18 months to 22.5 months.

   It is proposed that a new definition for the "R" notation be applied in Technical Specification Table 4.3-11, for Functional Unit 1.b. License Amendment Request 95-0027 (DBNPS letter Serial Number 2405) proposes that the "R" notation be defined as "At least once per 24 months." This is consistent with the guidance provided in by Generic Letter 91-04. Technical Specification 4.0.2 would continue to apply which would allow increasing the new surveillance interval on a non-routine basis from 24 months to 30 months.

As shown on the attached marked-up Technical Specification pages, the Allowable Values for TS 3.3.2.2, Steam and Feedwater Rupture Control System Instrumentation (SFRCS) Table 3.3-12, Functional Unit 2 (Steam Generator Level - Low) are proposed to be replaced by a single Allowable Value and the associated Trip Setpoint is proposed for deletion. The new allowable value has been calculated in accordance with ISA S67.04 - 1994, "Setpoints for Nuclear Safety-Related Instrumentation" (ISA S67.04) and ISA RP67.04 - 1994, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation," (ISA R67.04) and encompasses the channel functional test. The proposed Allowable Value is to be defined as applicable to the Channel Functional Test only by application of the "*" footnote in TS Table 3.3-12. As shown on the attached marked-up Technical Specification pages, the Limiting Condition for Operation and Action "a" for TS 3.3.2.2, SFRCS Instrumentation, are proposed for revision to reflect the proposed changes to the Trip Setpoint and Allowable Value. Technical Specification Bases 3/4.3.1 and 3/4.3.2, Reactor Protection System and Safety System Instrumentation, is revised to reflect the proposed changes to the Trip Setpoints and Allowable Values.

These changes are consistent with NUREG-1430, "Standard Technical Specifications, Babcock and Wilcox Plants," dated April, 1995.

B. The design goal of the SFRCS is to prevent release of high energy steam, to automatically start the Auxiliary Feedwater system in the event of a main steam line or main feedwater line rupture, to automatically start the Auxiliary Feedwater system on the loss of both main feed pumps or the loss of all four Reactor Coolant pumps, and to prevent steam generator overfill and subsequent spillover into the main steam lines. The SFRCS also provides a trip signal to the Anticipatory Reactor Trip system.

The SFRCS is required to ensure an adequate feedwater supply to the NSSS steam generators to remove reactor decay heat during periods when the normal feedwater supply and/or the electric power supply to essential auxiliaries has been lost. One auxiliary feedwater supply is available for each steam generator.

The initiating circuits of the SFRCS are the sensing circuits monitoring the following station parameters:

1. Main steam line pressure

2. Main feedwater/steam generator reverse differential pressure

3. Steam generator level

4. RC pump monitor

The SFRCS consists of two identical redundant and independent channels. Each channel consists of two complementary logic channels. The logic channels are identical and are maintained

separate and independent. Each complementary logic channel monitors the same plant parameters and provides a trip signal when any of the measured variables indicates a limiting condition is being reached. The trip output of each complementary logic channel is combined in the protection channel in a two-out-of-two logic.

In the event of a main steam line rupture, the SFRCS will close both main steam isolation valves, close both main feedwater control and stop valves and trip the main turbine when the pressure in the main steam line drops below the setpoint. The Auxiliary Feedwater System will also be initiated at this level, and both auxiliary feed pump turbines will be aligned with the unaffected steam generator. After automatic initiation of the auxiliary feed system, the operator may assume manual control. The manual control system is essential, and a manual speed control is provided for each turbine at the main control board and the auxiliary shutdown panel to control the auxiliary feedwater flow to each steam generator.

In the event of a main feedwater line rupture, the SFRCS will close both main steam isolation valves, close both main feedwater control and stop valves, trip the main turbine and initiate the auxiliary feedwater system when the pressure downstream of the last check valve in a main feedwater line to a steam generator exceeds upstream pressure by more than the SFRCS Main Feedwater/Steam Generator reverse differential pressure setpoint.

The "auto-essential" steam generator level control includes a dual setpoint. Following automatic actuation of auxiliary feedwater by the SFRCS, steam generator level will be controlled to the minimum level required to maintain natural circulation if no Safety Features Actuation System Level 2 actuation (low RCS pressure or high reactor building pressure) occurs. For accident conditions where both auxiliary feedwater and Safety Features Actuation System Level 2 are automatically actuated, the auto-essential level control will maintain a minimum actual level of 120 inches above the lower tube sheet.

The SFRCS is not an initiator, nor a contributor, to the initiation of an accident described in the USAR. The SFRCS and SFRCS actuated equipment are designed to allow single failure without preventing the system from performing the required operation. The SFRCS is designed to withstand physical damage or loss of function caused by earthquakes. The SFRCS will mitigate the consequences of an accident by initiating Auxiliary Feedwater, isolating a ruptured steam generator and redirect Auxiliary Feedwater flow to the intact steam generator.

C. As required by NUREG-0136, "Safety Evaluation Report for The Davis-Besse Nuclear Power Station, Unit 1," dated December 1976, Section 7.4.1; the channel calibration surveillance interval was reduced to quarterly from 18 months for the Steam Generator Level - Low Functional Unit. Attachment 2, item E.1, to the Facility

Operating License, NPF-3 stipulated that the four steam generator level switches be replaced with level transmitters. The quarterly surveillance interval was changed to 18 months by Amendment No. 4 to Facility Operating License No. NPF-3 for the Davis-Besse Nuclear Power Station, Unit No. 1, dated July 8, 1977, as a result of replacing the steam generator level switches with level transmitters.

As discussed above, the proposed change follows the guidance of Generic Letter 91-04.

D. As a result of the above review, it is concluded that the licensing basis of Technical Specification 4.3.2.2.1 will not be invalidated by increasing the surveillance interval for channel calibrations from 18 months to 24 months for the Steam Generator Level - Low functional Unit and by continuing to allow application of Technical Specification 4.0.2 on a non-routine basis.

E. References

i. Davis-Besse Nuclear Power Station (DBNPS) Unit No. 1, Operating License NPF-3, Appendix A, Technical Specifications, through Amendment 212.

ii. Generic Letter 91-04, "Changes in Technical Specifications Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991.

iii. "Standard Technical Specifications for Babcock and Wilcox Pressurized Water Reactors," NUREG-0103, Revision 0, dated June 1, 1976.

iv. NUREG-0136, Safety Evaluation Report for The Davis-Besse Nuclear Power Station, Unit 1, dated December 1976 and Supplement No. 1.

v. Amendment No. 7 to Facility Operating License No. NPF-3 for the Davis-Besse Nuclear Power Station, Unit No. 1, dated November 29, 1977.

vi. NUREG-1430, "Standard Technical Specifications, Babcock and Wilcox Plants," dated April, 1995.

vii. ISA S67.04 - 1994, "Setpoints for Nuclear Safety-Related Instrumentation."

viii. ISA RP67.04 - 1994, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation."

3. Instrument Drift Study Analysis

A. Enclosure 2 of Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Support a 24-Month Fuel Cycle," dated April 2, 1991, identifies seven issues to be

addressed in justifying increased surveillance intervals to accommodate a 24 month fuel cycle.

The following sections address, by number, the first six of seven issues, specified in Enclosure 2 of Generic Letter 91-04, necessary to justify a cycle extension from 18 to 24 months. The seventh issue is discussed in the main body of this license amendment application.

The converter and bistable are checked by the monthly functional surveillance and the transmitter is checked each refueling interval under the calibration surveillance. The transmitter was analyzed separately from the converter/bistable. Time dependence was not evaluated for monthly functional data since this interval is not being extended. It is worth noting that since the drift study, these level transmitters were rescaled from 0 - 250 inches to 0 - 300 inches by Modification 95-0062. The effect of rescaling is taken into account when determining projected drift in inches of water.

SFRCS Steam Generator Level Low

1. A review of the as-found and as-left calibration data, for the SFRCS SG Level- Low instrument strings, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and additionally the System Performance Book. This review indicates that the projected drift for a 30 month period would be 1.115 inches using the previous 0 - 250 inch range. Linear extrapolation was used to convert this value to the new 0 - 300 inch range (1.2 x 1.115 inch = 1.338 inch). For conservatism, this value was then rounded up to 1.5" and used in the setpoint calculation.

   Since the Technical Specification allowable value for this parameter is changing, the number of times an as-found value was found outside the allowable value was not analyzed. The drift study data, which was reflected into the setpoint calculation, demonstrates the acceptable performance of these transmitters.

2. The 95/95 historical value for the transmitter drift, chosen to be the worst "k*s" (tolerance factor times standard deviation) between the two calibration points closest to the low trip setpoint was 0.341% of span.

3. Although there was significant evidence to support a conclusion of time independence for these level transmitters, since few data points were available past 30 months, there were slight nonconservative slopes of Drift vs. Time Since Last Test data plots, and there was a slight increase in the standard deviation for Drift vs. Time Since Last Adjustment data points greater than 30 months, time dependency was conservatively assumed. Based on the significant evidence supporting time independence, the square root method of extrapolation was utilized in determining a 30 month projected drift of 0.446% of span for the previous 0 - 250

inch range. As previously stated, the 0.446% (1.115 inch) value was modified to produce a value meaningful for the new 0 - 300 inch range.

4. The setpoint for SG Level - Low and the new allowable value for Technical Specifications were calculated per ISA S67.04 and ISA R67.04 and utilized the projected 30 month drift value determined by the drift study. No safety analysis revision was required. The Technical Specification allowable value proposed for revision as previously discussed.

5. This SFRCS steam generator level low trip instrument string does not control any plant parameters in an analog fashion, but rather provides protective action signals to initiate operation of actuated equipment. Therefore, this question is not applicable.

6. SFRCS SG Level - Low is used to protect against a loss of normal feedwater event as described in USAR section 15.2.8, Loss of Normal Feedwater. The only assumption contained in the safety analysis that is implemented by a surveillance test is that AFW flow reaches the SG within 40 seconds after SG level reaches 10" above the lower tube sheet. The 10" value is maintained by the setpoint calculation. The 40 second response time is still required by the SFRCS Technical Specifications and is verified by DBNPS surveillance procedure DB-SC-03255.

   The setpoint calculation contains the following assumptions which currently are or will be reflected in surveillance procedures.

   1. The accuracy of the M&TE utilized in the setpoint calculation was verified to be specified in the surveillance procedures for SFRCS SG Level - Low (DBNPS procedures DB-MI-03237 thru 03246).

   2. The static span and zero shift is taken into account in the calibration. This is documented in the data packages for each SFRCS SG level string. These data packages are used in conjunction with the above listed surveillance test procedures.

   3. Prior to implementation of this LAR, the above listed surveillance test procedures will be altered to test the transmitter independent of the signal monitoring equipment and to incorporate the calculated values into the acceptance criteria.

Summary of Licensing Basis, Surveillance Data, and Maintenance Records Review for Technical Specification 3.3.3.5.1 and Surveillance Requirement 4.3.3.5.1

1. A. Technical Specification (TS): 3.3.3.5.1, "Remote Shutdown Instrumentation"

   Surveillance Requirement (SR) 4.3.1.1.1, Table 4.3-6, Functional Units 2 through 6, Channel Calibrations

   Note: Functional Units 1 and 7 do not require a revision to current surveillance intervals to support a 24 month fuel cycle.

   B. System Affected:

   Remote Shutdown Monitoring Instrumentation

   C. USAR Sections:

   3D.1.15 Criterion - Control Room
   7.4.1.6 Auxiliary Shutdown Panel
   7.4.2.5 Auxiliary Shutdown Panel

2. Licensing Basis Review:

   A. Technical Specification 4.3.3.5.1 requires that a Channel Calibration be performed every 18 months in accordance with Table 4.3-6, Remote Shutdown Monitoring Instrumentation Surveillance Requirements. Technical Specification 4.0.2 is applicable which allows increasing the surveillance interval on a non-routine basis from 18 months to 22.5 months.

   It is proposed that a new definition for the "R" notation be applied in Technical Specification Table 4.3-6, for Instruments 2 through 6 inclusive. License Amendment Request 95-0027 (DBNPS letter Serial Number 2405) proposes that the "R" notation be defined as "At least once per 24 months." This is consistent with the guidance provided in Generic Letter 91-04. Technical Specification 4.0.2 would continue to apply which would allow increasing the new surveillance interval on a non-routine basis from 24 months to 30 months.

   B. If temporary evacuation of the control room is required due to some abnormal station condition, the operator can establish and maintain the station in a safe hot shutdown condition through the use of an Auxiliary Shutdown Panel located outside the control room. The following controls and instrumentation are provided on this panel to accomplish hot shutdown:

1. Pressurizer level indicators.

2. Pressurizer heater controls and control transfer switches (to or from the Main Control Boards).

3. RC pressure indicators.

4. RC temperature indicators.

5. Steam generator level indicators.

6. Main steam pressure indicators.

7. Auxiliary feed pump governor controls and control transfer switches (to or from the Main Control Boards).

8. Service water isolation valve switches and control transfer switches (to or from the Main Control Boards).

Two each of the above controls and instrumentation are provided and are identical and redundant to one another.

Use of the Auxiliary Shutdown Panel (ASP) to establish and maintain hot shutdown conditions is provided in the DBNPS procedures.

In accordance with General Design Criterion 19, the capability of establishing a hot shutdown condition and maintaining the station in a safe status during hot shutdown is considered an essential function. The ASP is provided with adequate manual controls and indications of monitored station variables to provide positive safe hot shutdown of the Reactor from outside the control room and maintain the station in a safe hot shutdown condition without exceeding the design limits of the Reactor Coolant system and components.

In as much as the station can be maintained in a safe hot shutdown condition from outside the control room until access to the control room is regained, the need for taking the station to a cold shutdown condition from outside the control room is not anticipated. However, the ability to bring the station to a cold shutdown condition from outside the control room exists with the present station design. Through local controls, all necessary functions can be performed outside the control room, and with proper manpower and coordination the station can be cooled down over an extended period of time. Such an action includes the formulation at that time of a procedure based on an assessment of the situation.

The manual control circuits located on the panel are designed such that any single failure will not prevent proper protective action (maintaining safe hot shutdown) when required. This is accomplished by fully redundant manual controls for the systems required for safe shutdown utilizing separate essential power supplies. To prevent interaction between the redundant systems, the manual control channels are wired independently and separated with no electrical connections between redundant manual control systems. Normal automatic control circuits and non-essential monitor circuits are electrically isolated from essential controls and indications to prevent jeopardizing the reliability of the systems required for safe shutdown.

The protection systems associated with the ASP have been separated from control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel that is common to the control and protection systems, leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems has been limited to ensure that safety is not significantly impaired.

The ASP has been designed for high functional reliability and in-service testability commensurate with the safety functions to be performed. The redundancy and independence designed into the Auxiliary Shutdown Panel are sufficient to ensure that no single failure results in loss of the protection function and that removal from service of any component or channel does not result in loss of the required minimum redundancy. The ASP has been designed to permit periodic testing when the reactor is in operation, including the capability to detect any loss of redundancy that may have occurred.

The ASP is designed to withstand damage or loss of function from earthquakes and is located in a building designed to protect the system from wind, flood and lightning.

C. The 18 month surveillance frequency for the channel calibration was identified in the original operating license and technical specifications issued for the DBNPS, dated April 22, 1977, consistent with NUREG-0103, "Standard Technical Specifications for Babcock and Wilcox Pressurized Water Reactors," Revision 0, dated June 1, 1976.

The Remote Shutdown Monitoring System is not an initiator, nor a contributor, to the initiation of an accident described in the Updated Safety Analysis Report. The remote Shutdown Monitoring System ensures that sufficient capability is available to permit shutdown and maintenance of Hot Standby of the plant from locations outside of the control room in the event control room habitability is lost.

As discussed above, the proposed change follows the guidance of Generic Letter 91-04.

D. As a result of the above review, it is concluded that the licensing basis of the Remote Shutdown Monitoring System will not be invalidated by increasing the surveillance interval for Technical Specification 4.3.3.5.1 Channel Calibrations from 18 months to 24 months and by continuing to allow application of Technical Specification 4.0.2 on a non-routine basis.

E. References

i. Davis-Besse Nuclear Power Station (DBNPS) Unit No. 1, Operating License NPF-3, Appendix A, Technical Specifications, through Amendment 212.

ii. Generic Letter 91-04, "Changes in Technical Specifications Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991.

iii. "Standard Technical Specifications for Babcock and Wilcox Pressurized Water Reactors," NUREG-0103, Revision 0, dated June 1, 1976.

iv. NUREG-0136, Safety Evaluation Report for The Davis-Besse Nuclear Power Station, Unit 1, dated December 1976 and Supplement No. 1.

3. Instrument Drift Study Analysis

A. Enclosure 2 of Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Support a 24-Month Fuel Cycle," dated April 2, 1991, identifies seven issues to be addressed in justifying increased surveillance intervals to accommodate a 24 month fuel cycle.

The following sections address, by number, the first six of seven issues, specified in Enclosure 2 of Generic Letter 91-04, necessary to justify a cycle extension from 18 to 24 months. The seventh issue is discussed in the main body of this license amendment application.

<u>Reactor Coolant System Temperature</u>

(TERC3A4 and TERC3B2 as read on TIRC3A4 and TIRC3B2)

For the RTDs and linear bridge modules, the first three issues of Generic Letter 91-04, Enclosure 2 are addressed in Enclosure 1, Reactor Protection System.

One deviation from normal procedure as described in the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS was involved in analyzing the signal converters. The path of interest runs from the module input through the auxiliary

output isolation amplifier. However, the only data available was taken from the module input through the primary output isolation amplifier. Since the gain takes place in a common amplifier, the two paths will have nearly identical drifts. Also, the only means of adjusting this module is via an operational amplifier common to both paths. However, to be conservative, the drift of the auxiliary output isolation amplifier was assumed to be ±1% of span, random and independent of the ±0.69% of span drift for the rest of the module. The value of ±1% of span, obtained via engineering judgment, was chosen because this value is reasonably conservative with respect to the amount of drift the auxiliary output isolation amplifier would experience. It is expected that this will account for any performance differences between the two isolation amplifiers.

1. Signal Converter modules - Historical drift exceeded the design basis/reference uncertainty only three times out of 101 calibrations for which data was reviewed. This constitutes acceptable performance.

   Indicators - Historical drift exceeded the design basis/reference uncertainty only twice out of 36 calibrations for which data was reviewed. This constitutes acceptable performance.

   As discussed in Enclosure 1, RTD and linear bridge module performance was encompassed by the values used to establish the 30 month projected drift for the entire instrument string. Since this 30 month projected drift has been shown to be acceptable (see discussion under issue 5 below), historical performance must also have been acceptable.

2. Signal Converter modules - The worst case 95/95% tolerance interval was ±0.182% of span.

   Indicators - Over the years, there have been 14 different percent span points used to satisfy the 9 point calibration check. In order to make the data manageable, 9 of the 14 points were selected to characterize indicator performance. This necessitated data column shifting, as described in the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS. Among the nine data points, the worst case 95/95% tolerance interval was ±2.507% of span.

3. Signal Converters - Data was assumed to be time dependent, however, since there were only three tests (out of more than 100) that indicated some time dependency, the data was extrapolated to 30 months via the square root method. The worst case 95/95% tolerance interval was ±0.69% of span.

   Indicators - Although there was evidence showing that drift was time dependent, it was clearly less than linear. Therefore, the data was extrapolated to 30 months using the square root method described in the "Instrument Drift Data Analysis Methodology and Assumptions," for DBNPS. The extrapolated data had a worst case

95/95% tolerance interval of 2.71% of span.

4. No safety related setpoints or analyses are associated with the Reactor Coolant System Temperature Channels, therefore, the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The 30 month projected drift for the entire instrument string was obtained by combining the individual drift values for the various components, including the RTDs and linear bridge modules. Since they were all random terms, the square-root-sum-of-squares technique was used, yielding a drift value of 3.01% of span. The design basis/reference uncertainty was also obtained by combining individual terms for the various components, yielding 2.32% of span. Although the 30 month projected drift for the string exceeded the design basis/reference uncertainty, the Auxiliary Shutdown Panel RC hot leg temperature strings are still considered acceptable for use in verifying the establishment of natural circulation heat removal through observation of (1) the difference between RC hot and cold leg temperatures being stable at less than 50 °F, and (2) incore thermocouples and RC hot leg temperature indications being coupled and tracking.

6. These instrument strings are not included in any setpoint calculations, and there are no conditions or assumptions of setpoint and/or safety analyses that must be reflected in plant surveillance test procedure acceptance criteria.

Reactor Coolant System Pressure

(PT6365A and PT6365B as read on PI6365A1 and PI6365B1)

1. A review of the as-found and as-left calibration data, for the Remote Shutdown Reactor Coolant System Pressure Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that, on no occasion has instrument drift exceeded acceptable limits for a calibration interval.

2. The instrument drift for the Reactor Coolant System Pressure Channels was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the Reactor Coolant System Pressure Channels. This was determined to be 0.663% of span based on the historical data from the calibrations.

3. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, it was conservatively assumed that the Reactor Coolant System Pressure Channels were time dependent. Therefore the 30 month drift was determined using linear extrapolation. The boundaries of the instrument drift were determined as described in item 2 above. The instrument drift for

the Reactor Coolant System Pressure Channels was determined to be 0.997% of span based on the data extrapolated to 30 months.

4. No safety related setpoints or analyses are associated with the Reactor Coolant System Pressure Channels, therefore, the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 0.997% of span. The design basis/reference uncertainty used in the drift study is 1.3688% of span. The 30 month projected drift is less than the design basis/reference uncertainty. Thus the 30 month projected Drift is acceptable for use. Based on this, these instruments will still be able to effect a safe plant shutdown.

6. A review of safety analyses and surveillance procedures associated with the Reactor Coolant System Pressures Indications was performed. No safety related setpoints or safety analyses are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

Pressurizer Level

(LTRC14-1 and LTRC14-3 as read on LIRC14-1 and LIRC14-2)

1. A review of the as-found and as-left calibration data for the Remote Shutdown Pressurizer Level Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the Pressurizer Level Indication Channels was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the Pressurizer Level Indication Channels. This was determined to be 2.442% of span based on the historical data from the calibrations.

3. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, it was conservatively assumed that the Pressurizer Level Indication Channels were time dependent. Therefore the 30 month drift was determined using linear extrapolation. The boundaries of the instrument drift were determined as described in item 2 above. The instrument drift for the Pressurizer Level Indication Channels was determined to be 5.386% of span based on the data extrapolated to 30 months.

4. No safety related setpoints or analyses are associated with the Pressurizer Level Indication Channels therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 5.386% of span. The design basis/reference uncertainty used in the drift study is 1.6038% of span. The 30 month projected drift is greater than the design/basis reference uncertainty. Although the 30 month projected drift is greater than the design basis reference uncertainty, these instruments will still be able to effect a safe plant shutdown based on the evaluation performed during the Instrument Drift Study. The operator actions associated with these instruments involve controlling pressurizer level during a plant shutdown from the Auxiliary Shutdown Panel following a control room fire or an evacuation of the control room. During these events, the pressurizer level would be controlled at approximately 100 inches. This number was chosen because it is well above the level of the pressurizer heaters and well below the top of the pressurizer thus minimizing the possibility of the pressurizer going solid (overfilling the pressurizer) or uncovering the pressurizer heaters. The maximum instruemnt error would cause indicated pressurizer level to be off by 17.2 inches (5.386% of span). This means that the level would be between 82.8 and 117.2 inches when controlling pressurizer level at 100 inches. 82.8 inches is substantially above the 43.8 inch level of the heaters and 117.2 is considerably less than the 320 inch maximum of the instruments (actual top of the pressurizer is above 320 inches). Thus, the error associated with LIRC14-1 and LIRC14-2 is not large enough to cause the pressurizer level to increase or decrease significantly enough to cause the pressurizer to overfill or to uncover the pressuirzer heaters.

6. A review of safety analyses and surveillance procedures associated with the Pressurizer Level Indication Channels was performed. No safety related setpoints or safety analyses are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

Steam Generator Outlet Steam Pressure

(PTSP12A2 and PTSP12B1 as read on PISP12A1 and PISP12B1)

1. A review of the as-found and as-left calibration data, for the Remote Shutdown SG Outlet Steam Pressure Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the SG Outlet Steam Pressure channels was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the SG Outlet Steam Pressure channels. This was determined to be 26.22 psig based on the historical data from the calibrations.

3. The data was not clearly time independent based on the analysis performed. To be conservative, it was assumed that the SG Outlet Steam Pressure channels were time dependent. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 30 month drift was determined using the square root method of extrapolation. The boundaries of the instrument drift were determined as described in item 2 above. The instrument drift for the SG Outlet Steam Pressure channels was determined to be 43.632 psig based on the data extrapolated to 30 months.

4. No safety related setpoints or analyses are associated with the SG Outlet Steam Pressure Indication channels therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 43.632 psig The previously assumed design basis/reference uncertainty used in the setpoint is 26.35 psig. Although the 30 month projected drift is greater than the design basis/reference uncertainty, these instruments will still be able to be used to place the plant in a safe shutdown condition from the Auxiliary Shutdown Panel if the control room becomes inaccessible. Steam Generator pressure indication supports decay heat removal via the Auxiliary Feedwater System and the Main Steam Safety Valves (MSSV) or Atmospheric Vent Valves (AVV). Based on engineering judgment, the 30 month projected drift of 43.63 psig is acceptable because it would not prevent the operator from removing decay heat via the SGs, nor would it prevent them from adequately controlling SG pressure. If SG pressure indication experienced the worst case drift in either direction, the operator would observe the discrepancy between indicated pressure and the expected MSSV and/or AVV setpoints. The operator would then control SG pressure at a different indicated value to compensate for the instrument error.

6. A review of safety analyses and surveillance procedures associated with the SG Outlet Steam Pressure channels was performed. No safety related setpoints or safety analyses are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

<u>Steam Generator Startup Range Level</u>

(LTSP9A3 and LTSP9B3 as read on LISP9A3 and LISP9B3)

1. A review of the as-found and as-left calibration data, for the Remote Shutdown SG Startup Range Level Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the SG Startup Range Level Indication Channels was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the SG Startup Range Level Indication Channels. This was determined to be 3.178% of span based on the historical data from the calibrations.

3. The data was not clearly time independent based on the analysis performed. To be conservative, it was assumed that the SG Startup Range Level Indication Channels were time dependent. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 30 month drift was determined using the square root method of extrapolation. The boundaries of the instrument drift were determined as described in item 2 above. The instrument drift for the SG Startup Range Level Indication Channels was determined to be 4.143% of span based on the data extrapolated to 30 months.

4. No safety related setpoints or analyses are associated with the SG Startup Range Level Indication Channels therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 4.143% of span. The design basis/reference uncertainty used in the drift study is 1.65% of span. The 30 month projected drift is greater than the design basis/reference uncertainty. Although the 30 month projected drift is greater than the design basis/reference uncertainty, these instruments will still be able to effect a safe plant shutdown based on the evaluation performed during the Instrument Drift Study. No operator actions are taken based on these instruments during normal operations. These indicators are used when the control room is evacuated to maintain steam generator level at 49 inches (post reactor trip). The 30 month projected drift is ±4.143% which is ±10.36 inches. The 49 inch level is a guide based on convenience and maintaining some inventory in the steam generators. There are no precise level requirements that need to be maintained. The purpose of these instruments is to maintain the plant in a safe shutdown condition. A safe shutdown condition can be maintained with the steam generator level at 49 ±10.36 inches. No calculations or safety assumptions use these instruments, therefore, no calculations or safety analysis require changes.

6. A review of safety analyses and surveillance procedures associated with the SG Startup Range Level Indication Channels was performed. No safety related setpoints or safety analyses are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

Summary of Licensing Basis, Surveillance Data, and Maintenance Records Review for Technical Specification 3.3.3.6 and Surveillance Requirement 4.3.3.6

1. A. Technical Specification (TS): 3.3.3.6, "Post-Accident Monitoring Instrumentation"

   Surveillance Requirement (SR) 4.4.6.1

   Functional Units 1 through 6, 10, 11, 13, 15, 16, 17, 19, Channel Calibrations

   Note: The Channel Calibrations for Functional Units 7, 8, 9, 14, 18, 20 and 21 are proposed to remain on a 18 month surveillance interval and the Channel Calibration for Functional Unit 12 is proposed to be increased to 24 month surveillance interval as discussed in License Amendment Request 95-0027 (DBNPS letter Serial Number 2405).

   B. System Affected:

   Post-Accident Monitoring Instrumentation.

   C. USAR Sections:

   3.11 Environmental Design of Mechanical and Electrical Equipment
   7.5 Safety Related Display Information
   7.13 Post Accident Monitoring System

2. Licensing Basis Review:

   A. Technical Specification 4.3.3.6 requires that a Channel Calibration be performed every 18 months in accordance with Table 4.3-10, Post Accident Monitoring Instrumentation Surveillance Requirements. Technical Specification 4.0.2 is applicable which allows increasing the surveillance interval on a non-routine basis from 18 months to 22.5 months.

   It is proposed that a new definition for the "R" notation be applied in Technical Specification Table 4.3-10 for Instruments 1 through 6 inclusive, 10, 11, 13, 15, 16, 17 and 19. License Amendment Request 95-0027 (DBNPS letter Serial Number 2405) proposes that the "R" notation be defined as "At least once per 24 months." This is consistent with the guidance provided in by Generic Letter 91-04. Technical Specification 4.0.2 would continue to apply which would allow increasing the new surveillance interval on a non-routine basis from 24 months to 30 months.

As shown on the attached marked-up Technical Specification pages, Technical Specification Table 4.3-10, Post-Accident Monitoring Instrumentation Surveillance Requirements, Instrument 6, is proposed for revision to identify that the Containment Wide Range Noble Gas Monitors Channel Calibration will continue to be performed on an 18 month interval. License Amendment Request 95-0027 (DBNPS letter Serial Number 2405) proposes that the "E" notation be defined as "At least once per 18 months."

B. The purpose of the Post Accident Monitoring System (PAMS) is to follow the course of an accident condition with wide range instrumentation, which will provide to the plant operators the essential safety status information allowing the operators to return the plant to a maintained, safe, shutdown condition.

The scope of the PAMS Category 1 instrumentation includes all electronic signal processing equipment and cabling from the safety grade, Class 1E sensors (channels 1 and 2 of each variable) to the post accident instrument racks in the main control room and cabinet room. The racks house the indicating, recording, storing, calculating, and displaying modules for the essential accident condition information.

As defined in Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident" Revision 3, dated May 1983 (RG 1.97) Category 1 instrumentation is intended for key variables, Category 2 generally applies to instrumentation for indicating system operating status, and Category 3 instrumentation provides for backup and diagnostic functions.

No single failure within the PAMS, its auxiliary support features, or its power sources, concurrent with a failure that is a condition or result of the specific accident will prevent the operator from being provided the essential information to determine the safety status of the Generating Station.

The PAMS consists of the following instrumentation:

1. Containment High Range Radiation Monitors

2. Containment Wide Range Pressure Monitors

3. Containment Normal Sump and Wide Range Water Level Monitors

4. Containment Hydrogen Monitors

5. Reactor Coolant System Subcooling Margin Monitors

6. Incore Thermocouples

7. PORV and Pressurizer Safety Valves Position Indicators

8. Wide Range Noble Gas Monitors

9. Reactor Coolant Hot Leg Level Monitoring (HLLMS)

10. Reactor Coolant Loop Pressure Monitors

11. Neutron Flux Detectors

12. Steam Generator Start-Up Range Level Indicators

13. Steam Generator Outlet Steam Pressure

14. Reactor Coolant Loop Outlet Temperature

15. Pressurizer Level

16. High Pressure Injection Flow

17. Low Pressure Injection (DHR) Flow

18. Auxiliary Feedwater Flow Rate

19. Borated Water Storage Tank Level

With the exception of Containment Normal Sump Level, RC System Subcooling Margin Monitors, and PORV and Pressurizer Safety Valves Position Indicators all instrumentation is Category 1.

Containment High Radiation Monitors and Wide Range Noble Gas Monitors

The Containment High Radiation Monitor consists of two (2) safety grade, electrically independent, physically separated gamma photon radiation level instrument strings, with a calibrated range of 10^{0}-10^{8} Rad/hr. Continuous indicators have been provided in the post accident racks located in the main control room. In addition, one string provides a signal output (non-class 1E) to the Technical Support Center (TSC) system and both strings provide an output (non-class 1E) to recorders in the radiation monitoring panels located in the main control room.

The Wide Range Noble Gas Monitors consists of two (2) major assemblies, Normal Range Monitors and Accident Range Monitors, which detect and measure the gross beta/gamma activity level of the isotopes present in gaseous form in the containment atmosphere or from the auxiliary building in the effluent release vents. The monitors utilize three detectors to cover the gaseous activity range from 10^{-7} µCi/cc to 10^{+5} µCi/cc. In addition, a collection system for particulates and halogens permits data gathering for levels at or below 10^{+2} µCi/cc. The channel calibration for the Wide Range Noble Gas Monitors will remain at 18 months.

Containment Wide Range Pressure Monitors

The Containment Wide Range Pressure Monitors consist of two (2) safety grade, Class 1E, electrically independent, and physically separated, pressure instrument strings with a maximum calibrated range of 200 psia. Local indicators are provided in the post accident panels in the main control room.

One of the signals goes to the Technical Support Center (TSC).

Containment Normal Sump And Wide Range Water Level Monitors

The Containment Normal Sump and Wide Range Water Level Monitors each consist of two (2) safety grade water level instrument strings. Each normal range sump pit level instrument has an indicator in the main control room with a range of 0-4 feet. Actual sump pit depth is 2 feet 7 inches.

The wide range water level monitors each have an indicator in the main control room with a range of 0-55 feet (i.e., containment bottom to 600,000 gallon calculated CTMT flood level). The wide range sensors overlap approximately 4 inches with the normal range sensors. Both normal and wide range instruments provide Non-Class 1E signals to the station computer. Also one each of the normal and wide range signals goes to the Technical Support Center (TSC).

Containment Hydrogen Monitors

The containment Hydrogen Analyzers, although they are considered part of the plant post-accident monitoring instrumentation, have their Operability requirements are located in Technical Specification 3/4.6.4.1, Hydrogen Analyzers. The surveillance frequencies for the Hydrogen Analyzers are not affected by the this License Amendment Request.

Reactor Coolant System Subcooling Margin Monitors

The Reactor Coolant (RC) System Subcooling Margin Monitors consist of two (2) installed safety grade, Class 1E, electrically independent, physically separated instrument processor strings. Each processor channel is provided with signal inputs from 100 ohm RTD detector instrument strings and pressure instrument strings (Hot Leg Temperature 120-920°F and Wide Range Reactor Pressure 0-2500 psig). The processor channels calculate RCS subcooling and display the calculated value on non-Class 1E digital meters located in the main control room.

Incore Thermocouples

The Channel Calibration frequency for these instruments will remain at 18 months.

PORV and Pressurizer Safety Valves Position Indicators

The PORV and Pressurizer Safety Valves Position Indicators are designed to monitor the power operated relief valve and safety valves positions. Flow through these valves generates acoustical levels or vibration which is detected on the discharge pipe by piezoelectric sensors that provide a charged output.

An alarm module to test and display annunciator conditions and Open/Closed light indication is provided in the main control room. In addition, signal outputs are provided to the Technical Support Center (TSC), station annunciator, and station computer.

PORV Block Position Indication

The PORV Block Valve Position indication instrumentation surveillance interval extension to 24 months was submitted to the NRC via License Amendment Request 95-0027 (DBNPS letter Serial Number 2405).

Reactor Coolant Hot Leg Level Monitoring

The RC Hot Leg Level Monitoring System (HLLMS) instrument strings (one per hot leg) are classified as important to safe operation, but not nuclear safety related, and are designed to safety Class 1E for the electrical portion up to and including the isolation device wired to non Class 1E equipment. The piping portions of the HLLMS are designed as ASME Section III Class 1 from the reactor coolant system tie-ins to the first isolation valve and Section III Class 2 from the first isolation up to and including the instrument shut off valves.

The transmitters and sensing lines from each hot leg pipe are spatially separated. The lower tap for each transmitter is common, but each line is separately routed to the respective transmitter. Electrical separation for each redundant channel is provided by the routing of cable in separate conduits. Redundant Class 1E power is provided to each channel.

The HLLMS provides a means to trend reactor coolant inventory. The HLLMS provides supplementary information to assist the operator in the assessment of the effectiveness of automatic safety functions (ESFAS).

The HLLMS is only operational when the reactor coolant pumps are not running, and natural circulation is possible.

The Level Transmitter and density compensation signals are sent to the plant computer. An HLLMS algorithm takes these signals and RCS flow, temperature, pressure, and pump status signals and executes to determine actual hot leg level. The level can be accessed and displayed provided that the RCS pumps are off and the RCS is not experiencing rapid depressurization.

Reactor Coolant Loop Pressure Monitors

The RC Loop Pressure Monitors consist of two safety grade, Class 1E, electrically independent, physically separated, extended range pressure instrument strings with a calibration range of 0-3000 psig and two wide range (0-2500) psig pressure instrument strings associated with the Safety Features Actuation System. Indicators are provided in both the post accident panels in the main control room and the auxiliary shutdown panel. In addition, isolated signal outputs are provided to a chart recorder and the Technical Support Center (TSC).

Neutron Flux Detectors

The Channel Calibration frequency for these instruments will remain at 18 months.

Steam Generator Start-up Range Level Indicators

The Steam Generator (SG) Start-up Range Level Indicator consists of four (4) safety grade, Class 1E, electrically independent, physically separated readouts. Two read outs are 0-250 inches and two are 0-300 inches. Indicators are located on the main control board, fed from the Auxiliary Shutdown Panels, and on the Post Accident Monitoring (PAM) panels fed from the Steam and Feedwater Rupture Control System.

Steam Generator Outlet Steam Pressure

The Post Accident Monitoring System contains two (one per SG) safety grade Steam Generator Outlet Steam Pressure strings with indicators in the control room and corresponding plant computer points. The range of these strings is 0-1200 psig. These strings are redundant to two (one per SG) non-safety grade Steam Generator Outlet Steam Pressure strings with indicators in the control room and corresponding plant computer and Technical Support Center (TSC) computer points.

Reactor Coolant Loop Outlet Temperature

The Post Accident Monitoring System contains four (two per loop) safety grade RC loop Outlet Temperature strings with indicators in the control room and corresponding plant computer points. Two of these computer points also go to the Technical Support Center (TSC). These strings have a range of 120-920°F.

Pressurizer Level

The Post Accident Monitoring System contains two safety grade, Pressurizer Level strings with 0-120 inch range indication in the control room and corresponding plant computer points. One of these signals also goes to the Technical Support Center (TSC).

High Pressure Injection Flow

The Channel Calibration frequency for these instruments will remain at 18 months.

Low Pressure Injection (DHR) Flow

The Channel Calibration frequency for these instruments will remain at 18 months.

Auxiliary Feedwater Flow Rate

The Channel Calibration frequency for these instruments will remain at 18 months.

Borated Water Storage Tank Level

The Channel Calibration frequency for these instruments will remain at 18 months.

C. The 18 month surveillance frequency for the channel calibration was identified in the original operating license and technical specifications issued for the DBNPS, dated April 22, 1977 for Functional Units 1 through 8 of TS Table 4.3-10 consistent with NUREG-0103, "Standard Technical Specifications for Babcock and Wilcox Pressurized Water Reactors," Revision 0, dated June 1, 1976.

Functional Units 9 through 14 of TS Table 4.3-10, were added by Amendment 37 to to Facility Operating License No. NPF-3 for the Davis-Besse Nuclear Power Station, Unit No. 1, dated March 24, 1981. Functional Units 15 through 21 of TS Table 4.3-10 were added by Amendment 84 to to Facility Operating License No. NPF-3 for the Davis-Besse Nuclear Power Station, Unit No. 1, dated March 13, 1985. In both amendments the 18 month surveillance frequency was identified for the channel calibration.

By Safety Evaluation Report dated November 25, 1987, the NRC documented its review and acceptance of the DBNPS Post Accident Monitoring System in regard to Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 3, dated May 1983. The 18 month surveillance frequency for the channel calibration remained unchanged as a result of this review.

The Post Accident Monitoring System is not an initiator, nor a contributor, to the initiation of an accident described in the Updated Safety Analysis Report. The Post Accident Monitoring System ensures that sufficient information is available on selected plant parameters to monitor and assess these variables following an accident.

As discussed above, the proposed change follows the guidance of Generic Letter 91-04.

D. As a result of the above review, it is concluded that the licensing basis of the Post Accident Monitoring System will not be invalidated by increasing the surveillance interval for Technical Specification 4.3.3.6 Channel Calibrations from 18 months to 24 months and by continuing to allow application of Technical Specification 4.0.2 on a non-routine basis.

E. References

i. Davis-Besse Nuclear Power Station (DBNPS) Unit No. 1, Operating License NPF-3, Appendix A, Technical Specifications, through Amendment 212.

ii. Generic Letter 91-04, "Changes in Technical Specifications Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991.

iii. "Standard Technical Specifications for Babcock and Wilcox Pressurized Water Reactors," NUREG-0103, Revision 0, dated June 1, 1976.

iv. NUREG-0136, Safety Evaluation Report for The Davis-Besse Nuclear Power Station, Unit 1, dated December 1976 and Supplement No. 1.

v. Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 3, dated May 1983.

3. Instrument Drift Study Analysis

A. Enclosure 2 of Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Support a 24-Month Fuel Cycle," dated April 2, 1991, identifies seven issues to be addressed in justifying increased surveillance intervals to accommodate a 24 month fuel cycle.

The following sections address, by number, the first six of seven issues, specified in Enclosure 2 of Generic Letter 91-04, necessary to justify a cycle extension from 18 to 24 months. The seventh issue is discussed in the main body of this license amendment application.

<u>Steam Generator Outlet Steam Pressure</u>

(PTSP12A2 AND PTSP12B1 as read on PISP12A and PISP12B)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring SG Outlet Steam Pressure Channels, was

made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the SG Outlet Steam Pressure Indicators was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the SG Outlet Steam Pressure Indicators. This was determined to be 14.736 psig based on the historical 18 month data from the calibrations.

3. The data was not clearly time independent based on the analysis performed. To be conservative, it was assumed that the SG Outlet Steam Pressure Indicators were time dependent. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 30 month drift was determined using the square root method of extrapolation. The boundaries of the instrument drift were determined as described in item 2 above for the data extrapolated to 30 months. The instrument drift for the SG Outlet Steam Pressure Indicators was determined to be 22.548 psig based on the data extrapolated to 30 months. A one-sided tolerance factor was used to calculate the 30 month projected drift because decisions based on the SG Outlet Steam Pressure Indicators are made on increasing pressure only (see item 5 below for discussion).

4. No safety related setpoints are associated with the SG Outlet Steam Pressure Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 22.548 psig. The previously assumed design basis/reference uncertainty used in the analysis is 11.76 psig. The 30 month projected drift is greater than the design basis/reference uncertainty. These indicators provide RG 1.97, type "A" variable information to the operators during a Steam Generator Tube Rupture design basis accident. They are used for controlling cooldown rate during RCS cooldown and depressurization to 500° F and 1000 psig. They are also used to control SG pressure between 980 and 1000 psig, in accordance with DBNPS procedure DB-OP-02000, "RPS, SFAS, SFRCS Trip or SG Tube Rupture," (DB-OP-02000).

   While the drift is larger than the design basis/reference uncertainty, it is span independent meaning that the relationship between the points does not change as the instruments drift. The basic statistics calculated for these instrument strings support the assumption that the drift is span independent. Based on this, it is acceptable to use the Steam Generator Pressure Indicators to show a change in pressure (an increasing or decreasing trend) but not the actual pressure for controlling RCS cooldown rate.

The SG pressure control band allows 50 psig of margin to the Main Steam Safety Valve (MSSV) setpoint of 1050 psig. The accident analysis assumes that after the affected SG is isolated, no additional release of radioactivity occurs, therefore, it is necessary to verify that the 30 month projected drift of 22.55 psig will not cause the total instrument string uncertainty to become large enough to challenge the MSSV setpoint. A calculation will be created for this purpose. If 50 psig of margin is insufficient, the control band may have to be lowered.

6. A review of safety analyses and surveillance procedures associated with the SG Outlet Steam Pressure Indicators was performed. No safety related setpoints are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

Reactor Coolant Loop Outlet Temperature

(TERC3A5, TERC3A6, TERC3B5 and TERC3B6 as read on TIRC3A5, TIRC3A6, TIRC3B5 and TIRC3B6)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring RC Loop Outlet Temperature Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not. except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the RC Loop Outlet Temperature Indicators was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the RC Loop Outlet Temperature Indicators. This was determined to be 0.3285% of span based on the historical 18 month data from the calibrations.

3. The analysis performed in the Drift Study clearly demonstrated that the RC Loop Outlet Temperature Indicators were time independent. Also, these instruments have not required adjustments in over 75 months. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 18 month data was used as the 30 month projected drift.

4. No safety related setpoints are associated with the RC Loop Outlet Temperature Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 0.3285% of span. The previously assumed design basis/reference uncertainty used in the analysis is 0.6161% of span. The 30 month projected drift is less than the design basis/reference uncertainty. Thus the 30 month projected drift is acceptable for use. Based on this, these

instruments will still be able to effect a safe plant shutdown as previously evaluated. An evaluation of the use of these indicators for the manual calculation of subcooling margin will be performed.

6. A review of safety analyses and surveillance procedures associated with the RC Loop Outlet Temperature Indicators was performed. No safety related setpoints are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

Reactor Coolant Loop Pressure Wide Range Instrument Strings

(PTRC2A4 and PTRC2B4 as read on PIRC2A4 and PIRC2B4)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring RC Loop Wide Range Pressure Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the RC Loop Wide Range Pressure Indicators was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the RC Loop Wide Range Pressure Indicators. This was determined to be 49.425 psig based on the historical 18 month data from the calibrations. A one-sided tolerance factor was used to calculate the 30 month projected drift because these instruments may be used to determine a loss of subcooling margin which will occur on decreasing pressure.

3. The data was not clearly time independent based on the analysis performed. To be conservative, it was assumed that the RC Loop Pressure Indicators were time dependent. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 30 month drift was determined using the square root method of extrapolation. The boundaries of the instrument drift were determined as described in item 2 above for the data extrapolated to 30 months. The instrument drift for the RC Loop Wide Range Pressure Indicators was determined to be 70.45 psig based on the data extrapolated to 30 months. A one-sided tolerance factor was used for the reasons discussed in item 2 above.

4. No safety related setpoints are associated with the RC Loop Wide Range Pressure Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 70.45 psig. The previously assumed design basis/reference uncertainty used in the analysis is 68.67 psig. The 30 month projected drift is greater than the

design basis/reference uncertainty. Although the 30 month projected drift is greater than the design basis/reference uncertainty, no specific actions are taken based on these instruments. An evaluation of the use of these indicators for the manual calculation of subcooling margin will be performed.
These instrument strings are used to verify compliance with Technical Specification 3.4.9.1, Reactor Coolant System - Pressure/Temperature Limits. The Technical Specification pressure/temperature curves are error corrected for the instrument string uncertainties to generate the curves utilized in DBNPS operating procedures. These procedures will be revised as necessary. No change to Technical Specification 3.4.9.1 is required.

6. A review of safety analyses and surveillance procedures associated with the RC Loop Wide Range Pressure Indicators was performed. No safety related setpoints are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

Reactor Coolant Loop Pressure Extended Range Instrument Strings

(PT6365A and PT6365B as read on PI6365A and PI6365B)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring RC Loop Extended Range Pressure Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the RC Loop Extended Range Pressure Indicators was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the RC Loop Extended Range Pressure Indicators. This was determined to be 0.718% of span based on the historical 18 month data from the calibrations.

3. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, it was assumed that the RC Loop Extended Range Pressure Indicators were time dependent. Therefore the 30 month drift was determined using linear extrapolation. The boundaries of the instrument drift were determined as described in item 2 above for the data extrapolated to 30 months. The instrument drift for the RC Loop Extended Range Pressure Indicators was determined to be 1.333% of span based on the data extrapolated to 30 months.

4. No safety related setpoints or are associated with the RC Loop Pressure Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 1.333% of span. The previously assumed design basis/reference uncertainty used in the analysis is 1.7632% of span. The 30 month projected drift is less than the design basis/reference uncertainty. Thus the 30 month projected drift is acceptable for use. Based on this, these instruments will still be able to effect a safe plant shutdown as previously evaluated. An evaluation of the use of these indicators for the manual calculation of subcooling margin will be performed.

6. A review of safety analyses and surveillance procedures associated with the Reactor Coolant Loop Pressure Indicators was performed. No safety related setpoints are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

Pressurizer Level

(LTRC14-1 and LTRC14-3 as read on LIRC14-3 and LIRC14-4)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring Pressurizer Level Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the Pressurizer Level Indicators was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the Pressurizer Level Indicators. This was determined to be 2.709% of span based on the historical 18 month data from the calibrations.

3. The data was not clearly time independent based on the analysis performed. To be conservative it was assumed that the Pressurizer Level Indicators were time dependent. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 30 month drift was determined using the square root method of extrapolation. The boundaries of the instrument drift were determined as described in item 2 above for the data extrapolated to 30 months. The instrument drift for the Pressurizer Level Indicators was determined to be 3.483% of span based on the data extrapolated to 30 months.

4. No safety related setpoints are associated with the Pressurizer Level Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 3.483% of span. The previously assumed design basis/reference uncertainty used in the analysis is 1.607% of span. The 30 month projected drift is greater than the design basis/reference uncertainty. The

Pressurizer Level instruments are used to determine pressurizer level if NNI power is lost to prevent the pressurizer heaters from being uncovered or the pressurizer from going solid (full) during normal operations or severe transients (accidents). The only actions taken based on the exact readings of the instruments are based on readings taken at the low end of the instrument range (50 inches decreasing). The analysis determined that the current level operating limit of 50 inches for the pressurizer level indicators LIRC14-3 and LIRC14-4 may not be sufficient to prevent the pressurizer heaters from becoming uncovered. An evaluation was performed and the level op[erating limit will be revised to 55 inches. These level indicators are acceptable for controlling pressurizer level at 100 inches as determined in the evaluation performed for the Instrument Drift Study. No calculations or safety related setpoints are associated with the Post Accident Monitoring application of LIRC14-3 or LIRC14-4.

6. A review of safety analyses and surveillance procedures associated with the Pressurizer Level Indicators was performed. No safety related setpoints are associated with the Post Accident Monitoring application of these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

<u>Steam Generator Startup Range Level - SFRCS Instrument Strings</u>

(LTSP9A3 and LTSP9B3 as read on LISP9A1 and LISP9B1)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring SG Startup Range Level Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the SG Startup Range Level Indicators was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the SG Startup Range Level Indicators. This was determined to be 4.237% of span based on the historical 18 month data from the calibrations.

3. The data was not clearly time independent based on the analysis performed. To be conservative it was assumed that the SG Startup Range Level Indicators were time dependent. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 30 month drift was determined using the square root method of extrapolation. The boundaries of the instrument drift were determined as described in item 2 above for the data extrapolated to 30 months. The instrument drift for the SG

Startup Range Level Indicators was determined to be 6.123% of span based on the data extrapolated to 30 months.

4. No safety related setpoints are associated with the SG Startup Range Level Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 6.123% of span. The previously assumed design basis/reference uncertainty used in the analysis is 1.65% of span. The 30 month projected drift is greater than the design basis/reference uncertainty. Although the 30 month projected drift is greater than the design basis/reference uncertainty, these instruments will still be able to effect a safe plant shutdown based on the evaluation performed during the Instrument Drift Study. There are various actions taken based on the indicated level, however, these actions do not require exact indication. The setpoints or action levels associated with LISP9A1, LISP9B1 were chosen based on convenience not precise levels. Only the dry steam generator level (16 inches per DBNPS procedure DB-OP-02000, Attachment 1) could be affected by the error associated with LISP9A1, LISP9B1, however, other indications are also used (pressure, temperature) to determine if the steam generator is actually dry. This is also not affected as the 16 inch level is just a guide. Based on this, these indicators are considered acceptable for this application.

6. A review of safety analyses and surveillance procedures associated with the SG Startup Range Level Indicators was performed. No safety related setpoints are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

<u>Steam Generator Startup Range Level - PAMS Instrument Strings</u>

(LTSP9A6 and LTSP9B6 as read on LISP9A6A and LISP9B6A)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring SG Startup Range Level Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the SG Startup Range Level Indicators was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the SG Startup Range Level Indicators. This was determined to be 1.227% of span based on the historical 18 month data from the calibrations.

3. The data was not clearly time independent based on the analysis performed. To be conservative it was assumed that the SG Startup Range Level Indicators were time dependent. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 30 month drift was determined using the square root method of extrapolation. The boundaries of the instrument drift were determined as described in item 2 for the data extrapolated to 30 months. The instrument drift for the SG Startup Range Level Indicators was determined to be 1.744% of span based on the data extrapolated to 30 months.

4. No safety related setpoints are associated with the SG Startup Range Level Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 1.744% of span. The previously assumed Design Basis/Reference Uncertainty used in the analysis is 0.5222% of span. The 30 month projected drift is greater than the design basis/reference uncertainty. Although the 30 month projected drift is greater than the design basis/reference uncertainty, these instruments will still be able to effect a safe plant shutdown based on the evaluation performed during the Instrument Drift Study. There are various actions taken based on the indicated level, however, these actions do not require exact indication. The setpoints or action levels associated with LISP9A6A and LISP9B6A were chosen based on convenience not precise levels. Only the dry steam generator level (16 inches per DBNPS procedure DB-OP-02000, Attachment 1) could be affected by the error associated with LISP9A6A and LISP9B6A, however, other indications are also used (pressure, temperature) to determine if the steam generator is actually dry. This is also not affected as the 16 inch level is just a guide. Based on this, these indicators are considered acceptable for this application.

6. A review of safety analyses and surveillance procedures associated with the SG Startup Range Level Indicators was performed. No safety related setpoints are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

<u>Containment High Range Radiation Monitors</u>

(RE4596A and RE4596B as read on RI4596AB and RI4596BB)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring Containment Vessel Post-Accident Radiation Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the Containment Vessel Post-Accident Radiation Indicators was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the Containment Vessel Post-Accident Radiation Indicators. This was determined to be 1.973% of span based on the historical 18 month data from the calibrations.

3. The analysis performed in the Instrument Drift Study clearly demonstrated that the Containment Vessel Post-Accident Radiation Indicators were time independent. Also, these instruments have not required adjustments since installation (over 70 months). Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 18 month data was used as the 30 month projected drift.

4. No safety related setpoints are associated with the Containment Vessel Post-Accident Radiation Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 1.973% of span. The previously assumed design basis/reference uncertainty used in the analysis is 1.5% of span. The 30 month projected drift is greater than the design basis/reference uncertainty. Although the 30 month projected drift is greater than the design basis/reference uncertainty, these instruments will still be able to effect a safe plant shutdown based on the evaluation performed during the Instrument Drift Study. Regulatory Guide 1.97 specifies an accuracy of 20% from all sources of error for radiation indication. Currently, 2.2% of the 20% total accuracy is attributed to the electronics in the instrument string when estimating the accuracy of the monitors. The 30 month projected drift (1.973%) is less than 2.2% therefore it is still acceptable under RG 1.97. There are no operator actions or safety analyses associated with these instruments. Also, only two of six data points utilized during calibrations had any drift. Since the instruments have never required an adjustment during calibration and the total drift associated with the indicators is small, they are considered acceptable for this application.

6. A review of safety analyses and surveillance procedures associated with the Containment Vessel Post-Accident Radiation Indicators was performed. No safety related setpoints are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

Reactor Coolant System Subcooling Margin Monitor

The RC System Subcooling Margin Monitor was divided into two major groups for analysis. The first group is the temperature inputs to the Subcooling Margin Monitor. The second group is the pressure inputs to the Subcooling Margin Monitor. The pressure inputs were further divided as described in section B below.

A. Reactor Coolant System Subcooling Margin Monitor - Temperature Inputs

(TERC3A5, TERC3B5, TERC3A6 and TERC3B6 as read on TDY4950 and TDY4951)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring RC System Subcooling Margin Monitor Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the RC System Subcooling Margin Monitor Indicators was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the RC System Subcooling Margin Monitor Indicators. This was determined to be 2.736 °F based on the historical 18 month data from the calibrations.

3. The analysis performed in the Drift Study clearly demonstrated that the RC System Subcooling Margin Monitor Indicators were time independent. Also, these instruments have not required adjustments in over 75 months. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 18 month data was used as the 30 month projected drift.

4. No safety related setpoints are associated with the RC System Subcooling Margin Monitor Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 2.736 °F. The previously assumed design basis/reference uncertainty used in the analysis is 4.472 °F. The 30 month projected drift is less than the design basis/reference uncertainty. Thus the 30 month projected drift is acceptable for use. Based on this, these instruments will still be able to effect a safe plant shutdown as previously evaluated.

6. A review of safety analyses and surveillance procedures associated with the RC System Subcooling Margin Monitor Indicators was performed. No safety related setpoints are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

B. Reactor Coolant System Subcooling Margin Monitor - Pressure Inputs

(PTRC2A4 and PTRC2B4 as read on TDY4950 and TDY4951)

The RC System Subcooling Margin Monitor Channels pressure inputs were divided into two sections for analysis under items 1, 2 and 3. A combined analysis was performed for items 3, 4, 5, and 6. The first section of the instrument string consists of the pressure transmitter and I/I converter. The second section consists of a V/V converter, V/I converter, I/V converter and the indicator.

PTRC2A4 and PTRC2B4 Through I/I Converter

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring RC System Subcooling Margin Monitor Channels (PTCR2A4 and PTRC2B4 through I/I converter), was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the RC System Subcooling Margin Monitor Indicators (PTCR2A4 and PTRC2B4 through I/I converter) was determined using data for each point (percent of span) at which data is taken during calibration. The second to worst case data point was used to establish the boundaries of the instrument drift for the RC System Subcooling Margin Monitor Indicators. Not using the worst case data point was justified because the worst case data point is at the highest point of the instrument range used in the calibration (2375 pisg). The Subcooling Margin Monitor is used to determine when to turn off the RCPs due to a loss of subcooling margin. The decision to turn off the RCPs on a loss of subcooling margin utilizes the remainder of the instruments' range (0 to 1875 psig). Due to the fact that the worst point is near the high point of the instruments range, the drift of this point would not reflect the performance of the instruments at the range used to determine if subcooling was lost. Based on this, the worst case point was not used to determine the 30 month projected drift for either portion of the pressure string. This was determined to be 1.032% of span based on the historical 18 month data from the calibrations.

3. The data was not clearly time independent based on the analysis performed. To be conservative it was assumed that the RC System Subcooling Margin Monitor Indicators (PTCR2A4 and PTRC2B4 through I/I converter) were time dependent. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 30 month drift was determined using the square root method of extrapolation. The boundaries of the instrument drift were determined as described in item 2 for the data extrapolated to 30 months. The instrument drift for the Reactor Coolant System

Subcooling Margin Monitor Indicators (PTCR2A4,B4 through I/I converter) was determined to be 1.762% of span based on the data extrapolated to 30 months.

V/V Converters Through TDY4950, TDY4951

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring RC System Subcooling Margin Monitor Channels (V/V converters through TDY4950 and TDY4951), was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the RC System Subcooling Margin Monitor Indicators (V/V converters through TDY4950 and TDY4951) was determined using data for each point (percent of span) at which data is taken during calibration. The second to worst case data point was used to establish the boundaries of the instrument drift for the RC System Subcooling Margin Monitor Indicators. Not using the worst case data point was justified because the worst case data point is at the highest point of the instrument range used in the calibration (2375 psig). The Subcooling Margin Monitor is used to determine when to turn off the RCPs due to a loss of subcooling margin. The decision to turn off the RCPs on a loss of subcooling margin utilizes the remainder of the instruments' range (0 to 1875 psig). Due to the fact that the worst point is near the high point of the instruments range, the drift of this point would not reflect the performance of the instruments at the range used to determine if subcooling was lost. Based on this, the worst case point was not used to determine the 30 month projected drift for either portion of the pressure string. The instrument drift was determined to be 11 psig based on the historical 18 month data from the calibrations.

3. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, it was assumed that the RC System Subcooling Margin Monitor Indicators were time dependent. Therefore the 30 month drift was determined using the method described in the Drift Study evaluation. This method was considered to be a conservative method of calculating the 30 month projected drift. The boundaries of the instrument drift were determined as described in item 2 above for the data extrapolated to 30 months. The instrument drift for the RC System Subcooling Margin Monitor Indicators (V/V converters through TDY4950 and TDY4951) was determined to be 13.825 psig based on the data extrapolated to 30 months.

Combined Analysis

(PTRC2A4 and PTRC2B4 as read on TDY4950 and TDY4951)

3. The instrument drift for the RC System Subcooling Margin Monitor Indicators was determined to be 46.17 psig based on the data extrapolated to 30 months for the combined pressure strings.

4. No safety related setpoints are associated with the RC System Subcooling Margin Monitor Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 46.17 psig. The previously assumed design basis/reference uncertainty used in the analysis is 31.8 psig. The 30 month projected drift is greater than the design basis/reference uncertainty. These instruments are used to determine when subcooling margin is lost so the reactor coolant pumps can be shut off before a loss of subcooling margin occurs. This is described in DBNPS calculation C-ICE-064.02-007. This calculation will be reviewed and updated with the drift study results as required and the minimum subcooling margin revised as necessary.

6. A review of safety analyses and surveillance procedures associated with the RC System Subcooling Margin Monitor Indicators was performed. No safety related setpoints are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

PORV and Pressurizer Safety Valve Position Indicator

(ZE4263, ZE4264, ZE4265, ZE4266, ZE4267 and ZE4268 as read on ZI4263A, ZI4264A, ZI4265A, ZI4266A, ZI4267A and ZI4268A)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring PORV and Pressurizer Safety Valve Position Indicator Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the PORV and Pressurizer Safety Valve Position Indicators was determined using data for each point (percent of span) at which data is taken during calibration. Data was taken at 19 different test points over the range of the instruments. Data at 4 of the points was shifted as described in the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, to obtain a reasonable amount of data for analysis. The worst case data point was used to establish the boundaries of the instrument drift for the PORV and Pressurizer Safety Valve Position Indicators. This was determined to be 2.697% of span

based on the historical 18 month data from the calibrations.

3. The analysis performed in the Drift Study clearly demonstrated that the PORV and Pressurizer Safety Valve Position Indicators were time independent. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 18 month data was used as the 30 month projected drift.

4. No safety related setpoints are associated with the PORV and Pressurizer Safety Valve Position Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 2.697% of span. The previously assumed design basis/reference uncertainty used in the analysis is 1.118% of span. The 30 month projected drift is greater than the design basis/reference uncertainty. Although the 30 month projected drift is greater than the design basis/reference uncertainty, these instruments will still be able to effect a safe plant shutdown based on the evaluation performed during the Instrument Drift Study. Gross indication of valve position (open or closed) is all that is required by NUREG-0578, "TMI 2 Lessons Learned Task Force Status Report and Short-Term Recommendations," NUREG-0737, "Clarification of TMI Action Plan Requirements," (item II.D.3) and RG 1.97, (Table 2). Since the indicators give only gross indication of valve position (that the valve is open or closed), the 30 month projected drift is acceptable even though it is greater than the design basis/reference uncertainty as the indicators will show if the valve is open or closed. No operator actions are taken based on incremental indication of valve position. Based on this information, no further evaluation of the PORV or Pressurizer Safety Valve Position indicators is required.

6. A review of safety analyses and surveillance procedures associated with the PORV and Pressurizer Safety Valve Position Indicators was performed. No safety related setpoints are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

<u>Containment Normal Sump Level</u>

(LE4617 and LE4618 as read on LI4617 and LI4618)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring Containment Normal Sump Level Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the Containment Normal Sump Level Indicators was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the Containment Normal Sump Level Indicators. This was determined to be 0.223 feet based on the historical 18 month data from the calibrations.

3. The analysis performed in the Drift Study clearly demonstrated that the Containment Normal Sump Level Indicators were time independent. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 18 month data was used as the 30 month projected drift.

4. No safety related setpoints are associated with the Containment Normal Sump Level Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 0.223 feet. The previously assumed design basis/reference uncertainty used in the analysis is 0.2194 feet. The 30 month projected drift is greater than the design basis/reference uncertainty. Although the 30 month projected drift is greater than the design basis/reference uncertainty, these instruments will still be able to effect a safe plant shutdown based on the evaluation performed during the Instrument Drift Study. A review of the data indicates that these instruments perform better than the worst case point implies. A total of 70 readings were taken for the instrument strings. Only 3 of the readings were not at the desired values. Five of the Seven points where data is taken had no points that were not at the desired values (the mean and standard deviation of the percent drift since last test data were zero). Based on this, these instrument strings are considered acceptable for Containment Vessel Normal Sump Level indication.

6. A review of safety analyses and surveillance procedures associated with the Containment Normal Sump Level Indicators was performed. No safety related setpoints are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

Containment Wide Range Water Level

(LT4594 and LT4595 as read on LI4594 and LI4595)

The Containment Wide Range Water Level has a compensating input from the Containment Wide Range Pressure instruments. This input was analyzed separately for items 1, 2, and 3. A combined analysis was performed for items 4, 5, and 6. The first instrument string consists of the pressure transmitter through the input to the dual scalar (PT4587 and PT4588 through PY4587B and PY4588A). The second instrument string consists of the level indicator through the level indicator (LT4594 and LT4595 as read on LI4594 and LI4595).

A. PT4587 and PT4588 through PY4587B and PY4588A - input to LY4595B and LY4594B

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring Containment Wide Range Pressure Channels input to Containment Wide Range Water Level, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the Containment Wide Range Pressure Indicators input to Containment Wide Range Water Level was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the Containment Wide Range Pressure Indicators input to Containment Wide Range Water Level. This was determined to be 0.736% of span based on the historical 18 month data from the calibrations.

3. The analysis performed in the Instrument Drift Study clearly demonstrated that the Containment Wide Range Pressure Indicators input to Containment Wide Range Water Level Indicators were time independent. Also, these instruments have not required adjustments in over 70 months. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 18 month data was used as the 30 month projected drift.

B. LT4594 and LT4595 as read on LI4594 and LI4595

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring Containment Wide Range Water Level Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the Containment Wide Range Water Level Indicators was determined using data for each point (percent of span) at which data is taken during calibration. The second to worst case data point was used to establish the boundaries of the instrument drift for the Containment Wide Range Water Level Indicators. The worst case point was not used because this point is at the bottom of the instrument range and the point was affected greatly by hysteresis. Further discussion is provided in the Drift Study evaluation. The drift was determined to be 8.895% of span based on the historical 18 month data from the calibrations.

3. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, it was assumed that the Containment Wide Range Water Level Indicators were time dependent. Therefore, the 30 month drift was determined using linear extrapolation. The boundaries of the instrument drift were determined as described in item 2 for the data extrapolated to 30 months. The instrument drift for the Containment Wide Range Water Level Indicators was determined to be 14.354% of span based on the data extrapolated to 30 months.

Combined analysis for the Containment Wide Range Water Level Instrument Strings Including the Pressure Compensation Input

4. No safety related setpoints are associated with the Containment Wide Range Water Level Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 14.354% of span. The previously assumed design basis/reference uncertainty used in the analysis is 2.854% of span. The 30 month projected drift is greater than the design basis/reference uncertainty. Since the 30 month projected drift of LI4594 and LI4595 is so large, DBNPS procedure DB-OP-02000, will be changed to use the CTMT Vessel Water Level (WR) instruments for trending level inside CTMT but not for exact indication of CTMT water level. Any decisions made based on these instruments will not require precise level indication when DBNPS procedure DB-OP-02000 is changed. Based on this, these instruments are considered acceptable for providing qualitative data to the control room for operator actions. Decisions will not be based on the indicated level on the instruments but rather on a change of indicated level.

   The pressure transmitter inputs to LY4594B and LY4595B from PY4588A and PY4587B provide a bias that affects the level transmitter output. The Pressure instrument string inputs to LY4594B and LY4595B were analyzed separately and it was determined that their 30 month projected drift is ±0.736%. this has a maximum effect of ±0.658% on the output of LY4594B, LY4595B. This shift will be irrelevant because it is much less than the ±14.354% 30 month projected drift for LY4594B and LY4595B.

6. A review of safety analyses and surveillance procedures associated with the Containment Wide Range Water Level Indicators was performed. No safety related setpoints are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

Containment Wide Range Pressure

(PT4587 and PT4588 as read on PI4587 and PI4588)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring Containment Wide Range Pressure

Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the Containment Wide Range Pressure Indicators was determined using data for each point (percent of span) at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the Containment Wide Range Pressure Indicators. This was determined to be 1.07 psia based on the historical 18 month data from the calibrations.

3. The analysis performed in the Drift Study clearly demonstrated that the Containment Wide Range Pressure Indicators were time independent. Also, these instruments have not required adjustments in over 70 months. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 18 month data was used as the 30 month projected drift.

4. No safety related setpoints are associated with the Containment Wide Range Pressure Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is 1.07 psia. The previously assumed design basis/reference uncertainty used in the analysis is 1.07 psia. Since the 30 month projected drift is equal to the design basis/reference uncertainty, it is still acceptable to use PI4587 and PI4588 as all current assumptions are still applicable. PI4587 and PI4588 are two of six containment pressure indicators that can be used to determine when to shut down the Hydrogen Dilution Blowers during post accident conditions (see DBNPS procedure DB-OP-02000, Table 3, Containment Monitoring and Control, for additional details). The Hydrogen Dilution Blowers are shut off when the indicated containment pressure reaches 32 psia. This number is based on being one-half of the design pressure of the containment structure. The other half is considered margin. The 30 month projected drift of PI4587 and PI4588 is 1.07 psia which is considerably less than 32.7 psia thus the 32 psia control point provides substantial margin. Also, containment pressure will increase very slowly during the accident scenario, which is the main reason this is a manual action not an automatic action (i.e., operators have plenty of time to take the required action). For these reasons, the 30 month projected drift of PI4587 and PI4588 is considered acceptable. Based on this, these instruments will still be able to effect a safe plant shutdown as previously evaluated.

6. A review of safety analyses and surveillance procedures associated with the Containment Wide Range Pressure Indicators was performed. No safety related setpoints are associated with these instruments therefore the specific criteria of Generic

Letter 91-04 Enclosure 2, Item 6 do not apply.

Reactor Coolant Hot Leg Level (Wide Range)

The Reactor Coolant Hot Leg Level (Wide Range) inputs were divided into four groups for analysis under items 1, 2 and 3. A combined analysis was performed for items 4, 5, and 6. The four groups of inputs are the Reactor Coolant Hot Leg Level Temperature Compensation, Reactor Coolant Hot Leg Temperature, Reactor Coolant Hot Leg Level and Reactor Coolant Hot Leg Wide Range Pressure.

A. Reactor Coolant Hot Leg Level Temperature Compensation

(TY5449 and TY5450 as read on computer points T767 and T768)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring Reactor Coolant Hot Leg Level Temperature Compensation Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the Reactor Coolant Hot Leg Level Temperature Compensation Indicators was determined using data for each point (percent of span) at which data is taken during calibration. Data was taken at 13 different test points over the range of the instruments. Data at 4 of the points was shifted as described in the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, to obtain a reasonable amount of data for analysis. The worst case data point was used to establish the boundaries of the instrument drift for the Reactor Coolant Hot Leg Level Temperature Compensation Indicators. This was determined to be 0.819% of span based on the historical 18 month data from the calibrations.

3. The data was not clearly time independent based on the analysis performed. To be conservative it was assumed that the Reactor Coolant Hot Leg Level Temperature Compensation Indicators were time dependent. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 30 month drift was determined using the square root method of extrapolation. The boundaries of the instrument drift were determined as described in item 2 above for the data extrapolated to 30 months. The instrument drift for the Reactor Coolant Hot Leg Level Temperature Compensation Indicators was determined to be 1.308% of span based on the data extrapolated to 30 months.

B. Reactor Coolant Hot Leg Temperature

(TERC3A5 and TERC3B5 as read on computer points T782 and T753)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring Reactor Coolant Hot Leg Temperature Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the Reactor Coolant Hot Leg Temperature Indicators was determined using data for each point (percent of span) at which data is taken during calibration. Data was taken at 12 different test points over the range of the instruments. Data at 2 of the points was shifted as described in the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, to obtain a reasonable amount of data for analysis. The worst case data point was used to establish the boundaries of the instrument drift for the Reactor Coolant Hot Leg Temperature Indicators. This was determined to be 0.405% of span based on the historical 18 month data from the calibrations.

3. The analysis performed in the Drift Study clearly demonstrated that the Reactor Coolant Hot Leg Temperature Indicators were time independent. Also, these instruments have gone 134 months without requiring an adjustment. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 18 month data was used as the 30 month projected drift.

C. Reactor Coolant Hot Leg Level

(LT5448A and LT5448B as read on computer points L720 and L721)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring Reactor Coolant Hot Leg Level Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the Reactor Coolant Hot Leg Level Indicators was determined using data for each point (percent of span) at which data is taken during calibration. Data was taken at 12 different test points over the range of the instruments. Data at 2 of the points was shifted as described in the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, to obtain a reasonable amount of data for analysis. The worst case data point was used to establish the boundaries of the instrument drift for the Reactor Coolant Hot Leg Level

Indicators. This was determined to be 2.6176% of span based on the historical 18 month data from the calibrations.

3. The analysis performed in the Drift Study clearly demonstrated that the Reactor Coolant Hot Leg Level Indicators were time independent. Also, these instruments have gone over 70 months without requiring an adjustment. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 18 month data was used as the 30 month projected drift.

D. Reactor Coolant Hot Leg Wide Range Pressure

(PTRC2A4 and PTRC2B4 as read on computer points P732 and P724, and PTRC2A3 and PTRC2B3 as read on computer points P733 and P725)

1. A review of the as-found and as-left calibration data, for the Post Accident Monitoring Reactor Coolant Hot Leg Wide Range Pressure Channels, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and the System Performance Book. This review indicates that instrument drift has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. The instrument drift for the Reactor Coolant Hot Leg Wide Range Pressure Indicators was determined using data for each point (percent of spa at which data is taken during calibration. The worst case data point was used to establish the boundaries of the instrument drift for the Reactor Coolant Hot Leg Wide Range Pressure Indicators. This was determined to be 1.548% of span based on the historical 18 month data from the calibrations.

3. The data was not clearly time independent based on the analysis performed. To be conservative it was assumed that the Reactor Coolant Hot Leg Wide Range Pressure Indicators were time dependent. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the 30 month drift was determined using the square root method of extrapolation. The boundaries of the instrument drift were determined as described in item 2 above for the data extrapolated to 30 months. The instrument drift for the Reactor Coolant Hot Leg Wide Range Pressure Indicators was determined to be 2.003% of span based on the data extrapolated to 30 months.

E. Reactor Coolant Hot Leg Level Wide Range - Combined Analysis

4. No safety related setpoints are associated with the Reactor Coolant Hot Leg Level Indicators therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value of two of the inputs to the Reactor Coolant Hot Leg Level (Wide Range) system are greater than the previously assumed design basis/reference uncertainty used in the analysis (DBNPS calculations C-ICE-064.02-004,

C-ECS-064B-001 and C-ECS-064.02-112). Since the 30 month projected drift is less than the design basis/reference uncertainty for two of the inputs and greater than the design basis/reference uncertainty for the other two inputs, the calculations will be reviewed and revisions made as necessary.

6. A review of safety analyses and surveillance procedures associated with the Reactor Coolant Hot Leg Level Indicators was performed. No safety related setpoints are associated with these instruments therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 6 do not apply.

Summary of Licensing Basis, Surveillance Data, and Maintenance Record Review for Technical Specification 3.4.3 and Surveillance Requirement 4.4.3

1. A. Technical Specification (TS) 3.4.3, Safety Valves and Pilot Operated Relief Valve - Operating

   Surveillance Requirement 4.4.3, Channel Calibration

   B. System Affected:

   Pilot Operated Relief Valve

   C. Updated Safety Analysis Report (USAR) Sections:

   5.2.2.3 Overpressure Protection
   5.5.10 Pressurizer
   5.5.14 Safety and Relief Valves
   7.7. Control Systems

2. Licensing Basis Review:

   A. Technical Specification 4.4.3 requires that for the pilot operated relief valve (PORV) a channel calibration check shall be performed every 18 months. Technical Specification 4.0.2 is applicable which allows increasing the surveillance interval on a non-routine basis from 18 months to 22.5 months.

   It is proposed that in Technical Specification 4.4.3 the words "performed every 18 months" be replaced with "performed every REFUELING INTERVAL." License Amendment Request 95-0018 (DBNPS letter Serial Number 2342) proposes that "REFUELING INTERVAL" be defined as "A period of time $\leq$ 730 days." This is consistent with the guidance provided by Generic Letter 91-04. Technical Specification 4.0.2 would continue to apply which would allow increasing the new surveillance interval on a non-routine basis from 24 months to 30 months.

   B. The Pressurizer PORV is set such that it will open before the code safety valves are opened. However, it should not open on any anticipated transients. BAW-1890, "Justification for Raising Setpoint for Reactor Trip on High Pressure," dated September 1985 identified that the turbine trip from full power would cause the largest overpressure transient. This report demonstrated that with a Reactor Protection System high pressure trip setpoint of 2355 psig the resulting overshoot in Reactor Coolant System pressure would be limited to 50 psi. Consequently, the minimum PORV setpoint of greater than 2435 psig accommodates both the RCS pressure overshoot and the RPS instrument string error of 30 psi.

The PORV is controlled by an on-off signal from an electronic pressure switch. The valve is opened when the pressurizer pressure exceeds the high pressure setpoint, and is closed when the pressure is reduced.

C. Requirements for the PORV setpoint, including the 18 month surveillance interval, were added by Amendment No. 33 to Facility Operating License No. NPF-3 for the Davis-Besse Nuclear Power Station, dated October 1, 1980 in response to IE Bulletin 79-05B, "Nuclear Incident at Three Mile Island - Supplement," dated April 21, 1979. The current setpoint was added by Amendment No. 128 to Facility Operating License No. NPF-3 for the Davis-Besse Nuclear Power Station dated December 28, 1988. As stated in the safety evaluation for Amendment No. 128; the change to raise the minimum PORV setpoint from greater then or equal to 2390 psig to greater than 2435 psig is considered acceptable because, with a minimum setpoint greater than 2435 psig, the PORV should not open during anticipated overpressure transients (the setpoint accommodates the 30 psi instrument error and 50 psi pressure overshoot), the actual PORV setpoint will remain at 2450 psig, and NUREG-0737, Items II.K.3.2 and II.K.3.7, are satisfied at the minimum setpoint of 2435 psig.

The PORV is not an initiator, nor a contributor, to the initiation of an accident described in the Updated Safety Analysis Report. The PORV is designed to limit challenges to the pressurizer code safety valves but is not credited in the mitigation of an accident described in the Updated Safety Analysis Report.

D. As a result of the above review, it is concluded that the licensing basis of the Pilot Operated Relief Valve will not be invalidated by increasing the surveillance interval for TS 4.4.3 from 18 months to 24 months and by continuing to allow the application of TS 4.0.2 on a non-routine basis.

E. References

i. Davis-Besse Nuclear Power Station (DBNPS) Unit No. 1, Operating License NPF-3, Appendix A, Technical Specifications, through Amendment 212.

ii. Generic Letter 91-04, "Changes in Technical Specifications Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991.

iii. "Standard Technical Specifications for Babcock and Wilcox Pressurized Water Reactors," NUREG-0103, Revision 0, dated June 1, 1976.

iv. USAR Section 5.2.[illegible]3, "Overpressure Protection."

v. USAR Section 5.5.10, "Pressurizer."

vi. USAR Section 5.5.14, "Safety and Relief Valves."

vii. USAR Section 7.7, "Control Systems."

viii. Amendment No. 33 to Facility Operating License No. NPF-3 for the Davis-Besse Nuclear Power Station, dated October 1, 1980.

ix. Amendment No. 128 to Facility Operating License No. NPF-3 for the Davis-Besse Nuclear Power Station dated December 28, 1988.

3. Instrument Drift Study:

A. Enclosure 2 of Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Support a 24-Month Fuel Cycle," dated April 2, 1991, identifies seven issues to be addressed in justifying increased surveillance intervals to accommodate a 24 month fuel cycle.

The following sections address, by number, the first six of seven issues, specified in Enclosure 2 of Generic Letter 91-04, necessary to justify a cycle extension from 18 to 24 months. The seventh issue is discussed in the main body of this license amendment application.

Pressurizer Pilot Operated Relief Valve (PORV)

(PTRC2A2, PTRC2B2, RPS1RC2313, RPS2RC2313, PICRC2, and PSHLRC2-5)

For the pressure transmitters, the first three issues of Generic Letter 91-04, Enclosure 2 are mainly addressed in Enclosure 1, Reactor Protection System.

1. Historical drift values for buffer amplifier module balance, scaling, and bias have not exceeded their 30 month projected drifts. The same holds true for the NNI PORV control circuitry. As discussed in Enclosure 1 none of the pressure transmitter extrapolated drift data points exceed the 30 month projected drift. Since the 30 month projected drift values have all been shown to be acceptable (see discussion under item 4 below), the historical drift values must also have been acceptable. In addition, the as-found trips of the PORV control circuitry have not ever been below the Technical Specification minimum value.

2. Buffer Amplifier Modules: These were analyzed for drift in the categories of balance, scaling, and bias. The 95/95% tolerance intervals for balance, scaling, and bias were calculated to be ±0.060% of span, ±0.087% of span, and ±0.046% of span, respectively.

NNI PORV Control Circuitry: This is tested by injecting a voltage into the summer module and increasing it until a high level trip is obtained. The 95/95% tolerance interval for the high level trip voltage was calculated to be ±0.827% of span.

3. Buffer Amplifier Modules: The data was extrapolated linearly to 30 months. This resulted in 95/95% tolerance intervals of ±0.111% of span, ±0.183% of span, and ±0.096% of span for balance, scaling, and bias, respectively.

   NNI PORV Control Circuitry: The square root method was used to extrapolate the data points to 30 months. The 95/95% tolerance interval calculated using the extrapolated data set for the high level trip was ±1.098% of span.

4. The basis for the PORV Allowable Value of 2435 psig is that the minimum PORV setpoint must accommodate the largest RCS pressure overshoot (50 psi) and the RPS high pressure instrument string error (30 psi), referenced to the RPS high pressure trip setpoint (2355 psig). This is so the PORV will not open on any anticipated transients. Subsequent to the establishment of the 2435 psig value, a new RPS string error of 20.54 psi was calculated (in 1988) for RC high pressure. Drift study results, including those for the pressure transmitter, were substituted into the RC pressure string error equation, resulting in a new string error of 25.12 psi. Since this new error is less than the 30 psi that the PORV Allowable Value is based upon, that value (2435 psig) remains acceptable as the minimum PORV setpoint.

5. The PORV does not control plant parameters, but is designed to limit challenges to to the pressurizer code safety valves. Therefore, this issue is not applicable.

6. The PORV control instrument strings are not included in any formal setpoint calculations, and there are no conditions or assumptions of setpoint and/or safety analyses that must be reflected in plant surveillance test procedure acceptance criteria.

4. Surveillance Data Review:

   A. The 18 month surveillance data for the Pilot Operated Relief Valve (PORV), RC2A, was reviewed for the period January 1, 1987 through December 31, 1994.

   B. The test results indicate zero failures over the time period reviewed for this component.

   C. Based on the review of the 18 month surveillance test results data, no additional actions are necessary or recommended to support this increase in the surveillance interval.

   D. Based on the historical good performance of these components, the low potential for significant increases in failure rates of these components under a longer test interval, and the introduction of new failure modes, it is concluded that it is acceptable to increase the the surveillance interval for TS 4.3.3 from 18 months to 24 months and that that there is no adverse effect on nuclear safety. Furthermore, it remains acceptable to allow the

continued application of TS 4.0.2 on a non-routine basis.

E. References:

i. DB-MI-03742, Pressurizer Power Relief Valve Channel Calibration Check

ii. DB-OP-03366, Reactor Coolant System Vent Path Operability.

5. Maintenance Records Review:

A. The 18 month maintenance records for the Pilot Operated Relief Valve (PORV), RC2A, were reviewed for the period January 1, 1987 through December 31, 1994.

B. The maintenance records indicate zero failures which would have resulted in the PORV being TS inoperable, and zero significant degradation cases over the time period reviewed for these components.

The PORV tends to develop seat leakage over an operating cycle, some of which can be severe. This leakage does not make the PORV inoperable, in that it can be isolated using the PORV isolation valve RC11. The PORV was last replaced in 1993 due to excessive leakage.

Problems prior to the time period being evaluated have been identified. Problems with the PORV and associated circuitry were identified under the System Review and Test Program in 1985 and 1986. These problems concerned valve operability, indication problems, and control circuit problems. Significant upgrades and testing on the PORV and associated equipment were performed as part of the Course of Action program. These upgrades and follow on testing demonstrated the ability of the PORV to perform its required function satisfactorily. Since this time period no major problems have been identified with the PORV.

C. Based on a review of the 18 month maintenance records no additional actions are necessary or recommended to support this increase in the surveillance interval.

D. Based on the historical good performance of this component, the low potential for significant increases in failure rates of this component under a longer test interval, and the introduction of no new failure modes, it is concluded that it is acceptable to increase the surveillance interval of TS 4.4.3 from 18 months to 24 months and that there is no adverse effect on safety. Furthermore, it is acceptable to allow continued application of TS 4.0.2 on a non-routine basis.

E. References:

i. DBNPS Maintenance Work Order 1-92-0353-00

Summary of Licensing Basis, Surveillance Data, and Maintenance Records Review for Technical Specification 3/4.4.6 and Surveillance Requirement 4.4.6.1.b

1. A. Technical Specification (TS): 3/4.4.6, "Reactor Coolant System Leakage - Leak Detection Systems"

   Surveillance Requirement (SR) 4.4.6.1.b, Channel Calibration

   Note: Surveillance requirements 4.4.6.1.a and c for the Containment Atmosphere Particulate Radioactivity Monitoring System and the Containment Atmosphere Gaseous Radioactivity Monitoring System are proposed to remain on a 18 month surveillance interval as discussed in License Amendment Request 95-0027 (DBNPS letter Serial Number 2405).

   B. System Affected:

   Containment Sump Level and Flow Monitoring System.

   C. USAR Sections:

   3D.1.26 Criterion 30 - Quality of Reactor Coolant Pressure Boundary
   5.2.4 Reactor Coolant Pressure Boundary Leak Detection System

2. Licensing Basis Review:

   A. Technical Specification 4.4.6.1.b requires that a Channel Calibration be performed every 18 months on the containment sump level and flow monitoring system of the Reactor Coolant System leakage detection system. Technical Specification 4.0.2 is applicable which allows increasing the surveillance interval on a non-routine basis from 18 months to 22.5 months.

   It is proposed that in Technical Specification 4.4.6.1.b the words "at least once per 18 months" be replaced with "at least once each REFUELING INTERVAL." License Amendment Request 95-0018 (DBNPS letter Serial Number 2342) proposes that "REFUELING INTERVAL" be defined as "A pe[illegible]d of time $\leq$ 730 days." This is consistent with the guidance [illegible]ided by Generic Letter 91-04. Technical Specification 4.0.2 would continue to apply which would allow increasing the new surveillance interval on a non-routine basis from 24 months to 30 months.

   B. The Reactor Coolant System leakage detection system includes the following:

      a. The containment atmosphere particulate radioactivity monitoring system.

b. The containment sump level/flow monitoring system.

c. The containment atmosphere gaseous radioactivity monitoring system.

The containment sump level and flow monitoring system design includes containment vessel normal sump level indication in the control room. Flow rates are obtained by monitoring pump run time and multiplying by a flow rate. Instrumentation and power supplies are not essential. The transmitter is mounted seismically. There are redundant normal sump levels and alarms with control room indication. They are non-essential and non-seismic. Wide and narrow range sump level indicators have been added to the containment sump design which are essentially powered and seismically mounted.

Technical Specification 4.4.6.2.1.b requires that Reactor Coolant System leakages be demonstrated, while in Modes 1-4, to be within limits by monitoring the containment sump level and flow indication at least once per 12 hours. This is satisfied in DBNPS procedures that calculate Normal Sump Flow Rate every shift. The "Flow Monitoring System" consists of determining how long each Containment Normal Sump Pump has run since the last reading and multiplying by the estimated flow rate of that pump. The volume of water pumped by each sump pump is added together to obtain the total amount of water pumped out of the sump during the observation period. This volume is then corrected by the difference in sump level (plus or minus) between the beginning and end of the observation period to obtain the total volume of water that leaked into the sump. That volume is divided by the observation time (minutes) to obtain the leak rate (gallons per minute) into the sump. This method is used instead of the installed flowmeter.

As described above, the flow monitoring system is based on sump level (part of the Instrument Drift Study), the sump pump run time, and the sump pump flow rate.

All systems used for reactor coolant system leakage detection can be calibrated during operation except the sump levels.

These detection systems are consistent with the recommendations of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.

Reactor Coolant System leakage to the containment atmosphere is in the form of liquid and vapor. The liquid drains to the containment vessel normal sump, and the vapor is condensed in the containment air coolers and also reaches the containment normal sump via a drain line from the coolers.

The containment vessel radiation monitors provide positive indication in the control room of Reactor Coolant System leakage.

Analyses of Reactor Coolant System inventory trends and containment normal sump level changes also provide positive indication of Reactor Coolant System leakage to the containment. Changes in the rate of increase in containment normal sump water level are an indication of an increase in total containment leakage. The sump contains 30 gallons per inch of height. Any significant increase in sump level will be detected in the control room on the station computer and annunciator and the level indicator.

C. The 18 month surveillance frequency for the channel calibration was identified in the original operating license and technical specifications issued for the DBNPS, dated April 22, 1977.

The containment sump level and flow monitoring system is not an initiator, nor a contributor, to the initiation of an accident described in the Updated Safety Analysis Report. The containment sump level and flow monitoring system provides indication to the control room operator of Reactor Coolant System leakage to the containment for evaluation against Technical Specification requirements for operational leakage.

As discussed above, the proposed change follows the guidance of Generic Letter 91-04.

D. As a result of the above review, it is concluded that the licensing basis of the containment sump level and flow monitoring system will not be invalidated by increasing the surveillance interval for Technical Specification 4.4.6.1 Channel Calibration from 18 months to 24 months and by continuing to allow application of Technical Specification 4.0.2 on a non-routine basis.

E. References

i. Davis-Besse Nuclear Power Station (DBNPS) Unit No. 1, Operating License NPF-3, Appendix A, Technical Specifications, through Amendment 212.

ii. Generic Letter 91-04, "Changes in Technical Specifications Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991.

iii. "Standard Technical Specifications for Babcock and Wilcox Pressurized Water Reactors," NUREG-0103, Revision 0, dated June 1, 1976.

iv. NUREG-0136, Safety Evaluation Report for The Davis-Besse Nuclear Power Station, Unit 1, dated December 1976 and Supplement No. 1.

v. Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.

3. Instrument Drift Study Analysis

A. Enclosure 2 of Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Support a 24-Month Fuel Cycle," dated April 2, 1991, identifies seven issues to be addressed in justifying increased surveillance intervals to accommodate a 24 month fuel cycle.

The following sections address, by number, the first six of seven issues, specified in Enclosure 2 of Generic Letter 91-04, necessary to justify a cycle extension from 18 to 24 months. The seventh issue is discussed in the main body of this license amendment application.

Containment Normal Sump Level

(LIT4617 and LIT4618)

These instrument strings also satisfy Technical Specification 3.3.3.6, Post-Accident Monitoring Instrumentation, Table 3.3-10, Item 15, Containment Sump Normal Level (Enclosure 4).

1. On no occasion has instrument drift resulted in the instruments being found out of tolerance or exceeded limits for a calibration interval. The string calibration data records for the two sump level indication strings, LI4618 and LI4617, indicate that the instruments were found in tolerance and left as is over 5 operating cycles, thus the instruments did not drift sufficiently enough in over 70 months to require adjustment.

2. Based on the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS, the value of drift for the Containment Normal Sump Level instruments is ±0.223 feet.

3. The data was then plotted to show the relationship between the drift (percent of span) versus the time since the last adjustment and drift versus time since last test. These instrument strings have gone over 70 months without requiring an adjustment. In fact, these instruments have not required an adjustment since they were installed. The long term plots of drift versus time since last adjustment did not show any time dependent characteristics. This justifies the assumption that the instruments are not time dependent. Therefore, the calculated drift value of ±0.223 feet is acceptable for a 30 month calibration interval.

4. No safety related setpoints, calculations, or operator actions are based on these instruments. Therefore the specific criteria of Generic Letter 91-04 Enclosure 2, Item 4 do not apply.

5. The projected 30 month drift value is ±0.223 feet. The previously assumed design basis reference uncertainty used in the setpoint analysis is ±0.2194 feet. However, the design basis/reference uncertainty, or tolerance of the instrument, is large because of

the accuracy of the digital indication which represents 2.5% of scale. Actual drift has historically been a fraction of the allowed tolerance. Additionally, the Containment Normal Sump Level instruments are not used for any decision points during a plant shutdown or accident scenario. They are used as alternate indications to confirm that for an identified reactor coolant system leak, the leak is inside containment. Therefore, the instrument errors caused by the drift are acceptable for the associated instrumentation.

6. No safety related setpoints are associated with the Containment Vessel Normal Sump Level. Sump level indication is not an initiator, nor a contributor, to the initiation of an accident described in the Updated Safety Analysis Report. It is an input, along with sump flow rate, to the RCS unidentified leakrate used to evaluate compliance with Technical Specification 3.4.6.2, Operational Leakage. However, the calculation subtracts a final level from an initial level during the performance of the Miscellaneous Instrument Shift Check Surveillance Test, which is completed at least every 12 hours. Since only a differential level, determined over a short time period, is utilized in the Surveillance Test, any long-term drift effects are eliminated from the calculation because the drift would equally affect the final and initial sump level readings.

Summary of Licensing Basis, Surveillance Data and Maintenance Records Review for Technical Specification 3.7.1.2 and Surveillance Requirements 4.7.1.2.1.d, 4.7.1.2.1.e and 4.7.1.2.2

1. A. Technical Specification (TS): 3.7.1.2, "Auxiliary Feedwater System"

   Surveillance Requirements (SR): 4.7.1.2.1.d, 4.7.1.2.1.e and 4.7.1.2.2

   B. System Affected:

   Auxiliary Feed Pump Turbine Steam Generator Level Control
   Auxiliary Feed Pump Suction Pressure Interlocks
   Auxiliary Feed Pump Turbine Inlet Steam Pressure Interlocks

   C. USAR Sections:

3.6.2.7.1.5	Main Steam to the Auxiliary Feed Pump Turbines
5.5.2.1	Steam Generator - Design Basis
7.4.1.3.1	SFRCS System Description
9.2.7	Auxiliary Feedwater System

2. Licensing Basis Review

   A. Technical Specification 4.7.1.2.1.d requires that the Auxiliary Feed Pump Turbine Steam Generator Level Control System be demonstrated Operable by performance of a Channel calibration every 18 months. Technical Specification 4.7.1.2.1.e requires that the Auxiliary Feed Pump Suction Pressure Interlocks be demonstrated Operable by performance of a Channel Calibration every 18 months. Technical Specification 4.7.1.2.2 requires that the Auxiliary Feed Pump Turbine Steam Pressure Interlocks be demonstrated Operable by performance of a Channel Calibration every 18 months.

   Technical Specification 4.0.2 is applicable to each of these Technical Specifications which allows increasing the surveillance interval on a non-routine basis from 18 months to 22.5 months.

   It is proposed that in each of these Technical Specifications the words "at least once per 18 months" be replaced with "at least once each REFUELING INTERVAL." License Amendment Request 95-0018 (DBNPS letter Serial Number 2342) proposes that "REFUELING INTERVAL" be defined as "A period of time < 730 days." This is consistent with the guidance provided by Generic Letter 91-04. Technical Specification 4.0.2 would continue to apply which would allow increasing the new surveillance interval on a non-routine basis from 24 months to 30 months.

B. The Operability of the Auxiliary Feedwater System ensures that the Reactor Coolant System can be cooled down to less than 280°F from normal operating conditions when the turbine driven main feedwater pumps are not available, or following a loss of four reactor coolant pumps, or a total loss of normal and reserve electrical power to promote natural circulation of the Reactor Coolant System.

Steam Generator level is controlled by modulating solenoid control valves. These valves assume the automatic level control function and the Auxiliary Feedwater Pump Turbine controller maintains a constant speed at its high speed stop setting. Automatic level control is accomplished by comparing a S/G level signal with a level setpoint providing an output signal to the valve controller to position the valve. The level control valves and the Auxiliary Feedwater Pump Turbine speed can be controlled manually from the control room.

The "auto-essential" steam generator level control includes a dual setpoint. Following automatic actuation of auxiliary feedwater by the Steam and Feedwater Rupture Control System, steam generator level will be controlled to the minimum level (49 inches) required to maintain natural circulation if no Safety Features Actuation System Level 2 actuation (low Reactor Coolant System pressure or high reactor building pressure) occurs. For accident conditions where both auxiliary feedwater and Safety Features Actuation System Level 2 are automatically actuated, the auto-essential level control will maintain a minimum actual level of 120 inches above the lower tube sheet. Natural circulation testing at the DBNPS demonstrated that a 35-inch (indicated) steam generator level of Auxiliary Feedwater provides adequate natural circulation for decay heat removal.

The Condensate Storage Tanks are the non-safety-related primary source of the water for the Auxiliary Feedwater System. When the auxiliary feedwater pumps are needed and either the Condensate Storage Tanks are not available or have been emptied by the Auxiliary Feedwater System, a safety-related transfer system transfers the suction from the Condensate Storage Tanks to the Service Water System. The Service Water System is the safety-related secondary source of the water and must be available for the associated Auxiliary Feedwater System train to the Operable. The transfer is initiated upon detection of a low suction pressure at the suction of the auxiliary feedwater pumps by suction pressure interlock switches. These pressure switches, upon sensing low suction pressure, will automatically transfer the suction of the auxiliary feedwater pumps to the Service Water System. On a sustained low-low suction pressure, additional Auxiliary Feedwater Pump Suction Pressure Interlocks will operate to close the steam supply valves to protect the turbine driven auxiliary feedwater pumps from cavitation. The steam supply valves will reopen automatically upon restoration of suction pressure to the pumps. Both the low and the low-low suction Auxiliary Feed Pump Suction Pressure Interlocks are required to

be Operable for Operability of the associated auxiliary feedwater train.

Pressure switches on the main steam lines are used to detect breaks in the portion of the pressurized auxiliary feedwater pump turbine steam piping in the Auxiliary Building downstream of the auxiliary feedwater pump turbine isolation valves. These pressure switches close the auxiliary feedwater pump turbine main steam inlet isolation valves if steam pressure decreases to less than the setpoint. A double-ended rupture in the steam piping upstream of these pressure switches would depressurize the piping back to the auxiliary feedwater pump turbine steam admission valves. Upon a low pressure signal from any set pair of pressure switches a signal is sent to automatically close the the isolation valves for the appropriate auxiliary feedwater pump turbine.

C. The current 18 month surveillance interval requirements were identified in the original license and technical specifications issued for the DBNPS, dated April 22, 1977 for the Auxiliary Feed Pump Turbine Steam Generator Level Control System, the Auxiliary Feed Pump Suction Pressure Interlocks and the Auxiliary Feed Pump Turbine Steam Pressure Interlocks.

In its Safety Evaluation Report dated February 21, 1984, concerning TMI Action Plan item II.E.1.1 the NRC accepted the automatic transfer of the auxiliary feedwater suction to the service water system and an automatic isolation of the auxiliary feedwater turbine steam inlet lines due to low auxiliary feedwater pump suction pressure. In its Safety Evaluation Report dated June 1986, concerning restart of the DBNPS, the NRC accepted modifications to the suction pressure transfer setpoint. The 18 month surveillance requirement was unaffected in both Safety Evaluation Reports.

The Auxiliary Feed Pump Turbine Steam Pressure Interlocks surveillance requirement was modified by Amendment No. 131 to Facility Operating License No. NPF-3 for the Davis-Besse Nuclear Power Station, Unit No. 1, dated April 25, 1989. This Amendment stated that the Operability of the Auxiliary Feed Pump Turbine Inlet Steam Pressure Interlocks is required only for high energy line break concerns and does not affect Auxiliary Feedwater System Operability. The Channel Calibration 18 month surveillance requirement remained unchanged.

The Auxiliary Feedwater System is not an initiator, nor a contributor, to the initiation of an accident described in the Updated Safety Analysis Report. The Auxiliary Feedwater System is an engineered safety feature system that is relied upon to aid in preventing core damage in the event of transients such as loss of normal feedwater, loss of reactor coolant pumps or loss of normal and reserve electrical power.

As discussed above, the proposed change follows the guidance of Generic Letter 91-04.

D. As a result of the above review, it is concluded that the licensing basis of the Auxiliary Feed Pump Turbine Steam Generator Level Control System, the Auxiliary Feed Pump Suction Pressure Interlocks and the Auxiliary Feed Pump Turbine Steam Pressure Interlocks will not be invalidated by increasing the surveillance interval for Channel Calibrations from 18 months to 24 months and by continuing to allow application of Technical Specification 4.0.2 on a non-routine basis.

E. References

i. Davis-Besse Nuclear Power Station (DBNPS) Unit No. 1, Operating License NPF-3, Appendix A, Technical Specifications, through Amendment 211.

ii. Generic Letter 91-04, "Changes in Technical Specifications Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991.

iii. "Standard Technical Specifications for Babcock and Wilcox Pressurized Water Reactors," NUREG-0103, Revision 0, dated June 1, 1976.

iv. NUREG-0136, Safety Evaluation Report for The Davis-Besse Nuclear Power Station, Unit 1, dated December 1976 and Supplement No. 1.

v. NUREG-1177, Safety Evaluation Report Related to The Restart of Davis-Besse Nuclear Power Station, Unit 1, Following The Event of June 9, 1985, dated June 1986.

vi. DBNPS System Description SD-015 Rev. 3, Auxiliary Feedwater System.

3. Instrument Drift Study Analysis

A. Enclosure 2 of Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Support a 24-Month Fuel Cycle," dated April 2, 1991, identifies seven issues to be addressed in justifying increased surveillance intervals to accommodate a 24 month fuel cycle.

The following sections address, by number, the first six of seven issues, specified in Enclosure 2 of Generic Letter 91-04, necessary to justify a cycle extension from 18 to 24 months. The seventh issue is discussed in the main body of this license amendment application.

For purposes of the Drift Study, each of the pressure switch strings involved was combined for the evaluation of instrument drift.

Auxiliary Feed Pump Turbine Inlet Steam Pressure Interlocks

(PSL106A, PSL106B, PSL106C, PSL106D, PSL107A, PSL107B, PSL107C, PSL107D)

1. A review of the as-found and as-left calibration data, for the Auxiliary Feed Pump Turbine Inlet Steam Pressure Interlock pressure switches, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and System Performance Book records. Review of the as-found data indicates that there have been no occasions where these devices required re-calibration due to having been found out of tolerance.

2. The 95/95% historical drift value for the pressure switches, utilizing a one sided tolerance factor, was determined to be 1.856% of the 75 PSIG span.

3. Using collected data, the Percent Drift Since Last Test was reviewed to determine the drift for a 30 month interval following the "Instrument Drift Data Analysis Methodology and Assumptions" for DBNPS.

   Without clear indication that the drift is independent of time, each data point (percent drift since last test) was linearly extrapolated to 30 months. The projected drift is 4.020% of span per 30 months which is equal to 3.015 psi per 30 months.

4. The Auxiliary Feed Pump Turbine (AFPT) Inlet Steam Pressure Interlock setpoints are not based on Updated Safety Analysis Report Chapter 15 analysis but are designed to function to allow decay heat removal via steam to the AFPT until the Steam Generator temperature is low enough that cooldown can be transferred to the Decay Heat Removal system. Since it was determined that the 30 month projected drift was larger than the associated value in the existing setpoint calculation, the applicable calculation was revised to incorporate the 30 month drift value resulting in a change to the field setpoint. The setpoint was chosen to provide margin from the steam-line isolation requirement (on decreasing pressure) and to provide margin to avoid premature AFW isolation (on increasing pressure) during plant cooldown.

5. The Auxiliary Feed Pump Turbine Inlet Steam Pressure Interlock pressure switches close the auxiliary feedwater pump turbine main steam inlet isolation valves if steam pressure decreases to less than the setpoint. As discussed in item 4 above the the 30 month drift value was incorporated into the existing setpoint calculation resulting in a change to the field setpoint.

6. A review of channel functional, channel calibration, and channel check Surveillance Test procedures against design conditions and assumptions in the setpoint calculation was conducted during the Drift Study Review. The review indicated that these procedures

did not reflect the assumptions of the existing setpoint calculation with respect to the specified test gauge accuracy. A Potential Condition Adverse to Quality Report was initiated to address this issue. It was resolved by determining that sufficient conservative margin had been assumed in the calculation which could accommodate the larger test gauge accuracy. The revised setpoint calculation, to accommodate the 24 Month drift, stated assumptions, including the revised field setpoint, will be reflected in the surveillance procedures.

Auxiliary Feed Pump Suction Pressure Interlocks

(PSL4928A, PSL4928B, PSL4929A, PSL4929B, PSL4930A, PSL4930B, PSL4931A, PSL4931B)

1. A review of the as-found and as-left calibration data, for the Auxiliary Feed Pump Suction Pressure Switches, was made from Technical Specification Surveillance Procedures, Maintenance Work Orders, Instrumentation and Controls Maintenance Shop Records, and System Performance Book records. Review of the as-found data indicates that there have been a few occasions where these devices were found out of the surveillance test acceptance criteria tolerance. Since these device setpoints are not based on an analytical or safety limit, this is acceptable.

2. The 95/95% historical drift value for the pressure switches, utilizing a one sided tolerance factor and not taking credit for the conservative mean (drift value becomes simply the tolerance factor times the standard deviation), was determined to be 2.271% of the 5.8 PSIG of span.

3. The drift was found to be independent of time, therefore the 30 month projected drift is the same as the 95/95% historical drift value at 2.271% of span.

4. For both sets of pressure switches, since there is no analytical or safety analysis limit being protected, there is not an associated Technical Specification Allowable Value, and the 30 month historical drift value is only slightly larger than the existing surveillance test tolerance, no change to the existing field setpoint nor do tolerances need to be altered due to the extended interval.

5. This issue is addressed in item 4 above.

6. Since there is no safety limit being protected and there is no Technical Specification setpoint specified for these pressure switches, no formal setpoint calculations exist. Therefore, a revie of other design documents and assumptions against channel functional, channel calibration, and channel check surveillance test procedures was conducted during the Drift Study Review. It was found that for the Condensate Storage Tank/Auxiliary Feedwater Pump Suction Path Interlock pressure switches, although surveillance test procedures appropriately reflected the

duel-sided as-left setpoint tolerance specified in design documentation, the same design documentation specified an acceptable as-found setpoint tolerance as one-sided. The remaining requirements for both the Auxiliary Feedwater Pump Turbine Steam Isolation and Auxiliary Feedwater Pump Suction Path Interlock pressure switches were being met in the existing surveillance test procedures.

Given the 30 month projected drift values for the Auxiliary Feedwater Pump Turbine Steam Isolation pressure switches, Design performed a review of the field setpoint and tolerances and determined that the existing setpoint and tolerances were adequate for a 30 month surveillance test interval. Give the 30 month projected drift values for the Auxiliary Feedwater Pump Suction Path Interlock pressure switches, Design is performing an ongoing review of the adequacy of the setpoint and tolerances for a 30 month surveillance test interval and will resolve the design documentation tolerance discrepancy as part of this review. If setpoint or tolerance values change as a result of this review, the surveillance test procedures will be appropriately altered.

Auxiliary Feed Pump Turbine Steam Generator Level Control System

(LTSP9A3, LTSP9A4, LTSP9B3, LTSP9B4, LY6451J, LY6452J, LY6459J, LY6460J, ZT6451, ZT6452, ZT6459, ZT6460)

For purposes of the Drift Study, each string involved two level transmitters, converters, a proportional only controller, a positioner, and a modulating position solenoid valve.

For drift analysis, the instrument strings were divided into subgroups based on the testing methods.

Therefore, compliance with Generic Letter 91-04 Enclosure 2 is discussed separately for these subgroups of instruments.

1. Comparison of the as-found to as-left level transmitter calibration drift data with the 30 month projected drift value (1.716 %; determined by the drift study and utilized in the justification for acceptable operation of this instrument string) found no historical drift outside the 30 month projected drift value.

   Comparison of the as-found to as-left remainder of the instrument string to the controllers calibration drift data with the 30 month projected drift value (0.364 %; determined by the drift study and utilized by Design in their justification for acceptable operation of this instrument string) found no historical drift outside the 30 month projected drift value.

Since the signal converters (LY6451J, LY6452J, LY6459J and LY6460J) and position transmitters (ZT6451, ZT6452, ZT6459, ZT6460) are downstream of the controller, their errors (including drift) will be compensated by the controller to return the level to the setpoint. Therefore, their historical drift values were not compared to any design justified acceptable limit, but rather their instrument reference uncertainties (0.5% for the signal converters and 3.125% for the position transmitters). No historical drift values were outside the reference uncertainties.

2. For the level transmitters, a 95/95% historical value for drift (worst case for the 9 calibration points checked) was found to be 1.443%.

   For the remainder of the instrument string to the controllers, a 95/95% historical value for drift (worst case for the 9 calibration points checked) was found to be 0.268%.

   For the signal converters, a 95/95% historical value for drift (worst case for the 9 calibration points checked) was found to be 0.096%.

   For the position transmitters, a 95/95% historical value for drift (worst case for the 6 calibration points checked after outlier removal) was found to be 0.688%.

3. For the level transmitters, although plots of drift versus time did not show any time dependent characteristics, since very little data was available for intervals past 30 months, all drift data over one month was extrapolated via the square root method. The result, with outliers removed, was a 30 month projected drift value of 1.716% (worst case for the 9 calibration points checked).

   For the remainder of the instrument string to the controllers, there was a large amount of evidence, including the fact that instruments have gone over 70 months without a need for adjustment, to support a conclusion that the drift was time independent. However, there was one test whose results were contrary to that conclusion. Therefore, for conservatism, all drift data over one month was extrapolated via the square root method. The result, with no outliers requiring removal, was a 30 month projected drift value of 0.364% (worst case for the 9 calibration points checked).

   For the signal converters and the position transmitters, there was a significant amount of data past 30 months. In addition to other supporting evidence, since the drift for points less than 22.5 months was found to bound the drift for points greater than 22.5 months, the drift was determined to be time independent. Therefore, the 30 month projected drift remained the same as the 95/95% historical value for drift, 0.096% and 0.688%, respectively.

4. There are no safety analysis conditions associated with the level indication feature on the level indicating controllers.

5. Based on engineering judgment, it was determined that the 30 month projected drifts for the level transmitters and the remainder of the instrument string to the controllers was acceptable to provide the operators with appropriate indication for verifying a steam generator overfill event or determining which steam generator is affected during a minor steam line break.

   Based on a design review utilizing the drift study values in a graded approach to the instrument string uncertainties, it was determined that in the auto mode of operation, the instrument strings will change the Auxiliary Feedwater Pump level control valve position appropriately to maintain the necessary 36 inch and 120 inch analytical steam generator levels.

6. There are no safety analysis conditions or assumptions, such as setting tolerances, M&TE tolerances, or other testing related uncertainties, that need to be verified in the test procedures for the level indication feature on the level indicating controllers.

   For the Auxiliary Feedwater Pump level control valve position string, the 30 month projected drift value was incorporated into the design review in a graded approach to the instruemnt string uncertainties. No other testing related uncertainties are assumed in the design review.

   Assumptions for the level controller setpoints are properly verified in existing test procedures and do not require revision.

ATTACHMENT 1
FOR
LICENSE AMENDMENT REQUEST NUMBER 95-0024
(19 pages follow)