TRANSMITTAL OF PROPOSED CHANGES
TO GRAND GULF TECHNICAL SPECIFICATIONS

1. (GGNS - 16)

SUBJECT: Technical Specification Table 3.3.3-2, page 3/4 3-29.

DISCUSSION: The Trip Setpoint and Allowable Value for trip function D.2.a.3 Division 3, 4.16 KV Bus Undervoltage (Loss of Voltage) Time Delays in Table 3.3.3-2 should be changed. The Trip Setpoint and Allowable Value are presently incorrectly stated as (0.5 seconds) and (0.5 + 0.5, - 0.1 seconds), respectively. These values should be changed to a Trip Setpoint of (2.3 seconds) and an Allowable Value of (2.3 + 0.2, - 0.3 seconds).

JUSTIFICATION: In the event of bus undervoltage on the Division 3, 4.16 KV bus, the offsite power to the bus is tripped immediately. The bus undervoltage time delay relay will provide a start signal to the Division 3 diesel generator after the time delay. This time delay relay will also provide a permissive after the time delay to permit the diesel generator output breaker to close. Per NEDO-10905-2, this time delay for the permissive to allow the output breaker to close must be long enough for the HPCS pump motor residual voltage to decay to less than or equal to 25% of rated voltage.

The time delay from loss of voltage on the bus until the permissive for the diesel generator output breaker to close must be greater than the 1.1 seconds required for the HPCS pump motor residual voltage (if the pump were running at the time of loss of bus voltage) to decay to less than or equal to 25% of rated voltage. After the motor residual voltage has decayed to less than or equal to 25% of rated voltage, the diesel generator output breaker can be permitted to close when the diesel generator has reached rated speed and voltage.

The situation could occur where the HPCS pump motor is powered from offsite power and the Division 3 diesel generator is running. If undervoltage occurs on the Division 3 bus, the time delay relay will ensure that the HPCS pump motor residual voltage has decayed to less than or equal to 25% of rated voltage before the permissive is received to close the diesel generator output breaker. This would be the situation in the event of a LOCA (which initiated HPCS and started the diesel generator) followed by a subsequent loss of offsite power.

The proposed Trip Setpoint and the lower band of the Allowable Value ensures that adequate time is allowed for decay of residual voltage. The upper band of the Allowable Value is set at 2.5 seconds.

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The proposed Technical Specification change is more conservative than the information presented in the HPCS performance analysis (Figure A2-1, page 8 of NEDO-10905-2). The NEDO document considered a 3 second undervoltage sensing delay until the offsite power is tripped and the permissive for diesel generator output breaker closure is received.

SIGNIFICANT HAZARDS CONSIDERATION:

The proposed change to the Technical Specification is requested to reflect the actual design of the plant. The proposed values are more conservative than the information presented in the HPCS performance analysis (Figure A2-1, page 8 of NEDO-10905-2) referenced with GGNS FSAR and therefore constitute increased conservatism in comparison to the plant design bases. Thus, this change does not introduce a significant reduction in a margin of safety. Since the change does not involve a significant increase in the probability or consequences of an accident previously evaluated nor does it create the possibility of a new or different kind of accident from any accident previously evaluated, no significant hazards considerations are involved.

TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
D. LOSS OF POWER		
1. Division 1 and 2		
a. 4.16 kV Bus Undervoltage (Loss of Voltage)	1. 4.16 kV Basis 2912 volts	2912 +0, -291 volts
	2. 120 volt Basis 83.2 volts	83.2 +0, -8.3 volts
	3. Time Delay 0.5 seconds	0.5 +0.5, -0.1 seconds
b. 4.16 kV Bus Undervoltage (BOP Load Shed)	1. 4.16 kV Basis 3328 volts	3328 +0, -167 volts
	2. 120 volt Basis 95.1 volts	95.1 +0, -4.8 volts
	3. Time delay 0.5 seconds	0.5 +0.5, -0.1 seconds
c. 4.16 kV Bus Undervoltage (Degraded Voltage)	1. 4.16 kV Basis 3744 volts	3744 +93.6, -0 volts
	2. 120 volt Basis 107 volts	107 +2.7, -0 volts
	3. Time Delay 9.0 seconds	9.0 ± 0.5 seconds
2. Division 3		
a. 4.16 kV Bus Undervoltage (Loss of Voltage)	1. 4.16 kV Basis 3045 volts	3045 ± 61 volts
	2. 120 volt Basis 87 volts	87 ± 1.7 volts
	3. Time Delay ~~0.5~~ 2.3 seconds	~~0.5 + 0.5, -0.1~~ 2.3 +0.2,-0.3 seconds

1. (GGNS-16)

*See Bases Figure B 3/4 3-1.

#These are inverse time delay voltage relays or instantaneous voltage relays with a time delay. The voltages shown are the maximum that will not result in a trip. Lower voltage conditions will result in decreased trip times.

2. (GGNS - 87)

SUBJECT: Technical Specification 4.6.6.3.d.5 and 4.7.2.d.3, pages 3/4 6-54 and 3/4 7-6.

DISCUSSION: Technical Specifications 4.6.6.3.d.5 and 4.7.2.d.3 reference ANSI N510-1975 for testing the heat dissipation of the heaters in the Standby Gas Treatment System and the Control Room Emergency Filtration System. However, ANSI N510-1975 does not address heat dissipation testing of the heaters. The proposed change deletes the reference to ANSI N510-1975 for testing the heat dissipation of the heaters in the Standby Gas Treatment System and the Control Room Emergency Filtration System.

JUSTIFICATION: ANSI N510-1975 does not address heat dissipation testing of heaters. Therefore, the reference to this standard in Specifications 4.6.6.3.d.5 and 4.7.2.d.3 should be deleted.

INTERNAL INFORMATION:

The heat dissipation requirements of Specifications 4.6.6.3.d.5 and 4.7.2.d.3 will be verified on an 18 month frequency during system testing.

SIGNIFICANT HAZARDS CONSIDERATION:

The proposed change is a purely administrative change which corrects the Technical Specifications by deleting a reference to a non-applicable standard while leaving the intent and requirement of the specifications unchanged. This change to the Technical Specifications does not involve a significant reduction in a margin of safety and it does not involve a significant increase in the probability or consequences of an accident which has been previously evaluated, nor does it create the possibility of a new or different kind of accident from any accident previously evaluated. Therefore, the proposed change does not involve any significant hazards consideration.

NOTE: Technical Specification page changes marked with a PCOL number and circled are changes that were previously submitted to the NRC.

2. (GGNS-87)

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 18 months or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire or chemical release in any ventilation zone communicating with the subsystem by:

1. Verifying that the subsystem satisfies the in-place testing acceptance criteria and uses the test procedures of Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 4000 cfm ± 10%.

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978.

3. Verifying a subsystem flow rate of 4000 cfm ± 10% during system operation when tested in accordance with ANSI N510-1975.

c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978.

d. At least once per 18 months by:

1. Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence for the:

   a) LOCA, and

   b) Fuel handling accident.

2. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than ~~10.75~~ 9.2 inches Water Gauge while operating the filter train at a flow rate of 4000 cfm ± 10%.

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3. Verifying that the filter train starts and isolation dampers open on each of the following test signals:

   a. Drywell pressure - high,

   b. Reactor vessel water level - low low, level 2,

   c. Fuel handling area ventilation exhaust radiation - high, and

   d. Fuel handling area pool sweep exhaust radiation - high.

4. Verifying that the fan can be manually started.

5. Verifying that the heaters dissipate 50 ± 5.0 kW ~~when tested in accordance with ANSI N510-1975.~~

SURVEILLANCE REQUIREMENTS (Continued)

1. Verifying that the subsystem satisfies the in-place testing acceptance criteria and uses the test procedures of Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 4000 cfm ± 10%.

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978.

3. Verifying a subsystem flow rate of 4000 cfm ± 10% during subsystem operation when tested in accordance with ANSI N510-1975.

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c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Positon C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978.

d. At least once per 18 months by:

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 7.2 inches Water Gauge while operating the subsystem at a flow rate of 4000 cfm ± 10%.

2. Verifying that on each of the below isolation mode actuation test signals, the subsystem automatically switches to the isolation mode of operation and the isolation valves close within 4 seconds:

   a) High radiation in the outside air intake duct,
   b) High chlorine concentration in the outside air intake duct,
   c) High drywell pressure, and
   d) Low reactor water level.

3. Verifying that the heaters dissipate 20.7 ± 2.1 kW ~~when tested in accordance with ANSI N510-1975.~~

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter banks remove greater than or equal to 99.95% of the DOP when they are tested in-place in accordance with ANSI N510-1975 while operating the system at a flow rate of 4000 cfm ± 10%.

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorbers remove 99.95% of a halogenated hydrocarbon refrigerant test gas when they are tested in-place in accordance with ANSI N510-1975 while operating the system at a flow rate of 4000 cfm ± 10%.

3. (GGNS - 189, 334)

SUBJECT: Technical Specification 4.6.5.b.3 and 4.6.7.3.c, pages 3/4 6-45a and 3/4 6-59.

DISCUSSION: Technical Specification 4.6.5.b.3 currently requires verification of the operability of the drywell vacuum breaker isolation valve differential pressure actuation instrumentation with the setpoint at 1.0 psid. This isolation valve is required to open post LOCA when the drywell pressure is less than the containment pressure by less than 1.0 psid (e.g., when the drywell pressure minus containment pressure is greater than -1.0 psid). Therefore, in order to clarify the direction of the pressure differential required for opening, and thus the pressure differential to be used during surveillance testing, the parenthetical phrase (drywell minus containment) is added to Technical Specification 4.6.5.6.3 and the current 1.0 psid is correspondingly changed to -1.0 psid. In addition, an upper bound of 0.0 is to be specified for the allowable test value in order to provide a reasonable band within which a successful surveillance test may be conducted (i.e., the currently specified single value and pressure differential without specified tolerances prohibits conducting a practical and successful surveillance test). Considering instrument accurracy, the surveillance test acceptance band of -1.0 to 0.0 psid assures the isolation valve will open at a pressure differential well within the Allowable Values given in the FSAR (i.e., -1.6 to +1.6 psid).

Technical Specification 4.6.7.3.c presently requires verification of the operability of the drywell purge compressor discharge line vacuum breaker isolation valve pressure actuation instrumentation with an opening setpoint of 1.0 psid. For purpose of clarification, the parenthetical phrase (drywell minus containment) is to be inserted. In addition, a lower bound of 0.0 psid is to be placed on the surveillance test acceptance band, thus providing a reasonable band (as opposed to a single point value) within which a practical and successful surveillance test may be conducted.

JUSTIFICATION: As currently written, Technical Specification 4.6.5.b.3 and 4.6.7.3.c are unclear regarding the direction of the pressure differential to be used in conducting the required surveillance testing. In addition, and in both cases, a single point value without tolerance is given for the surveillance test acceptance criteria. A successful and practical surveillance test requires specification of acceptance criteria with a reasonable and acheivable tolerance. The proposed Technical Specification changes provide clarification regarding the direction of the pressure differential and defines a tolerance, or band, for the test acceptance criteria. Surveillance test results within the band given for the test acceptance criteria assures the corresponding valve will open within the required pressure values specified in the FSAR.

SIGNIFICANT HAZARDS CONSIDERATION:

The proposed Technical Specification change provides clarification of the intent of the Technical Specifications and assure that surveillance testing can be conducted per the original intent. Thus the proposed changes do not introduce a significant reduction in margin of safety. Since the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated nor does it create the possibility of a new or different kind of accident from any accident previously evaluated, no significant hazards considerations are involved.

3. (GGNS-189, 334)

SURVEILLANCE REQUIREMENTS (Continued)

3. By verifying the OPERABILITY of the vacuum breaker isolation valve differential pressure actuation instrumentation with the opening setpoint ~~1.0~~ of -1.0 to 0.0 psid (DRYWELL MINUS CONTAINMENT) by performance of a:

   a) CHANNEL CHECK at least once per 24 hours,

   b) CHANNEL FUNCTIONAL TEST at least once per 31 days, and

   c) CHANNEL CALIBRATION at least once per 18 months.

Note 1: Until restart after the first refueling outage, the following requirements shall apply:

3.6.5

c. With the position indicator of an OPERABLE drywell post-LOCA isolation valve for a vacuum breaker inoperable, verify the isolation valve to be closed at least once per 24 hours by local indication. Otherwise declare the isolation valve inoperable.

4.6.5.b.1

b. Verifying the position indicator for the vacuum breaker isolation valve OPERABLE by observing expected valve movement during the cycling test.

4.6.5.b.2

At least once per 18 months by:

   a) Verifying the pressure differential required to open the vacuum breaker, from the closed position, to be less than or equal to 1.0 psid~~, by use of an equivalent test weight and lever arm on the vacuum breaker~~, and

   b) Verifying the position indicator for the vacuum breaker isolation valve OPERABLE by performance of a CHANNEL CALIBRATION.

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3. (GGNS- 189, 334)

CONTAINMENT SYSTEMS

DRYWELL PURGE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.7.3 Two independent drywell purge system subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one drywell purge system subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS Continued

4.6.7.3 Each drywell purge system subsystem shall be demonstrated OPERABLE:

a. At least once per 92 days by:

1. Starting the subsystem from the control room, and

2. Verifying that the system operates for at least 15 minutes.

b. At least once per 18 months by:

1. Verifying a subsystem flow rate of at least ~~500~~ 1000 cfm during subsystem operation for at least 15 minutes.

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2. Verifying the pressure differential required to open the vacuum breakers on the drywell purge compressor discharge lines, from the closed position, to be less than or equal to 1.0 psid.

c. Verifying the OPERABILITY of the drywell purge compressor discharge line vacuum breaker isolation valve differential pressure actuation instrumentation with an opening setpoint of ~~1.0 psid~~ (0.0 TO 1.0 Psid (DRYWELL MINUS CONTAINMENT) by performance of a:

1. CHANNEL CHECK at least once per 24 hours,

2. CHANNEL FUNCTIONAL TEST at least once per 31 days, and

3. CHANNEL CALIBRATION at least once per 18 months.

4. (GGNS - 194)

SUBJECT: Technical Specification Tables 2.2.1-1 and 3.3.4.2-2, pages 2-4 and 3/4 3-41.

DISCUSSION: The subject Technical Specification Tables contain Trip Setpoints and Allowable Values for the turbine stop valve-closure and the turbine control valve-fast closure. The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of greater than or equal to 40 psig, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst case transient assuming the turbine bypass valves fail to open. This stop valve trip fluid setting of greater than or equal to 40 psig also inputs to the End-Of-Cycle Recirculation Pump Trip (EOC-RPT) which is part of the Reactor Protection System (RPS) and is an essential supplement to the reactor trip. The EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during closure of the turbine stop valves and fast closure of the turbine control valves. The proposed change to the turbine stop valve-closure Allowable Value is from the present greater than or equal to 0 psig to greater than or equal to 37 psig. The present Allowable Value of 0 psig was based on the lowest pressure the trip fluid could reach. The proposed Allowable Value is calculated from the setpoint of 40 psig and considers instrument accuracy and drift.

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection coincident with failure of the turbine bypass valves. The RPS initiates a trip when fast closure of the control valves is initiated by a low Electro Hydraulic Control (EHC) fluid pressure in the control valve of greater than or equal to 44.3 psig. This trip signal also inputs to the EOC-RPT. The proposed change to the turbine control valve fast closure Allowable Value is from the present greater than or equal to 41 psig to greater than or equal to 42 psig. The proposed change is based on calculations that consider instrument drift and accuracy subtracted from the Trip Setpoint.

The proposed change to Technical Specification Tables 2.2.1-1 and 3.3.4.2-2 adds a note to indicate that the stated setpoints for turbine stop valve-closure and turbine control valve-fast closure are initial setpoints. Final setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to the Commission within 90 days of test completion.

JUSTIFICATION: The proposed change to the turbine stop valve-closure trip Allowable Value from greater than or equal to 0 psig to greater than or equal to 37 psig reflects possible instrument inaccuracy and drift from the Trip Setpoint (greater than or

equal to 40 psig). The trip signal is detected by pressure transmitters and sent to the RPS through pressure indicating switches. The accuracy of the pressure transmitter is 0.5% of span (0-200 psig) and the assumed drift is 0.5% of span. The accuracy (includes drift) for the pressure indicated switch is 0.2% of span (0-200 psig). The Techncial Specification Allowable Value is then determined as follows:

Allowable Value = Setpoint - Accuracy - Drift

= 40 - 1-1-.4
= 37.6 psig

The Allowablve Value was rounded down to 37 psig. The RPS design specification requires detection of turbine stop valve closure motion before the valve is more than 10% closed or 70 milliseconds after start of valve closure, whichever comes first. The Trip Setpoint and Allowablve Value ensures that this response time is met.

The proposed change to the turbine control valve fast closure Allowablve Value from greater than or equal to 41 psig to greater than or equal to 42 psig reflects possible instrument accuracy and drift from the Trip Setpoint (greater than or equal to 44.3 psig). The calculation of the Allowable Value was performed in the manner discussed above for the stop valves. The RPS design specification requires initiation of a trip within 70 milliseconds after actual start of control valve fast closure. The Trip Setpoint and Allowablve Value ensures that this response time is met.

Since the Trip Setpoints are initial calculated values, startup testing will determine actual system response times and if changes are required to the setpoints, these changes will be submitted to the NRC within 90 days of test completion.

SIGNIFICANT HAZARDS CONSIDERATION:

The proposed change to the turbine stop valve closure and turbine control valve fast closure Allowable Values constitutes a more stringent control of the Trip Setpoints that provide input to the RPS. The proposed changes to the Allowable Values are calculated from the Trip Setpoint and consider instrument accuracy and drift. The Trip Setpoints and proposed Allowable Values are initial setpoints that will be verified during the startup testing and changes proposed to the NRC, if required. The Trip Setpoints and proposed Allowable Values are within the response time requirements by General Electric for RPS signal inputs. These changes do not cause a significant increase in the probability or consequences of an accident previously evaluated nor do they create the possibility of a new or different kind of accident from any accident previously evaluated. These changes do not represent a significant reduction in the margin of safety provided by the turbine stop valve-closure or turbine control valve fast closure Trip Setpoints. Therefore, these changes do not constitute a significant hazards consideration.

TABLE 2.2.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Intermediate Range Monitor, Neutron Flux-High	≤ 120/125 divisions of full scale	≤ 122/125 divisions of full scale
2. Average Power Range Monitor:		
a. Neutron Flux-High, Setdown	≤ 15% of RATED THERMAL POWER	≤ 20% of RATED THERMAL POWER
b. Flow Biased Simulated Thermal Power-High		
1) Flow Biased	≤ 0.66 W+48%, with a maximum of	≤ 0.66 W+51%, with a maximum of
2) High Flow Clamped	≤ 111.0% of RATED THERMAL POWER	≤ 113.0% of RATED THERMAL POWER
c. Neutron Flux-High	≤ 118% of RATED THERMAL POWER	≤ 120% of RATED THERMAL POWER
d. Inoperative	NA	NA
3. Reactor Vessel Steam Dome Pressure - High	1064.7 ≤ ~~1065~~ psig	1079.7 ≤ ~~1080~~ psig
4. Reactor Vessel Water Level - Low, Level 3	≥ 11.4 inches above instrument zero*	≥ 10.8 inches above instrument zero*
5. Reactor Vessel Water Level-High, Level 8	≤ 53.5 inches above instrument zero*	≤ 54.1 inches above instrument zero*
6. Main Steam Line Isolation Valve - Closure	≤ 6% closed	≤ 7% closed
7. Main Steam Line Radiation - High	≤ 3.0 x full power background	≤ 3.6 x full power background
8. Drywell Pressure - High	≤ 1.73 psig	≤ 1.93 psig
9. Scram Discharge Volume Water Level - High	≤ 60% of full scale	≤ 63% of full scale
10. Turbine Stop Valve - Closure	≥ 40 psig**	≥ 37 ~~0~~ psig
11. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ 44.3 psig**	≥ 42 ~~41~~ psig
12. Reactor Mode Switch Shutdown Position	NA	NA
13. Manual Scram	NA	NA

*See Bases Figure B 3/4 3-1.

**Initial Setpoint. Final Setpoint to be determined during startup tests program. Any required changes to this setpoint shall be submitted to the Commission within 90 days of test completion.

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4 (GGNS-194)

TABLE 3.3.4.2-2

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Turbine Stop Valve - Closure	≥ 40 psig*	≥ ~~0~~ 37 psig*
2. Turbine Control Valve - Fast Closure	≥ 44.3 psig*	≥ ~~41~~ 42 psig*

* Initial Setpoint. Final Setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to the Commission within 90 days of test completion.

5. (GGNS - 305, 745)

SUBJECT: Technical Specifications 4.8.1.1.2.a.5 and 4.8.1.1.2.d.9, pages 3/4 8-3 and 3/4 8-6.

DISCUSSION: Specification 4.8.1.1.2.a.5 presently requires load testing of diesel generators 11, 12, and 13 to greater than or equal to 50% of continuous load rating on a frequency as specified in Table 4.8.1.1.2-1 (no less often than once per 31 days). This test requires the diesel generators to start, synchronize onto the bus, and reach 50% load in less than or equal to 60 seconds and to operate with these loads for at least 60 minutes. The proposed change to the specification would increase the loading of the diesel generators during the above testing to greater than or equal to the maximum load each could experience on associated emergency buses for the design basis diesel generator loading accident (LOCA with loss of offsite power). The maximum load diesel generator 11 or 12 could see during this accident was calculated by adding the loads that are automatically sequenced on the buses to those that could be manually placed on the buses by operator action during the accident. The basis for loads that are automatically sequenced onto diesel generators 11 and 12 is found on FSAR tables 8.3-1 and 8.3-2. These two tables are presently being revised and the FSAR will be changed to reflect a LOCA load of 4774 KW for diesel generator 11 and 4289 KW for diesel generator 12. The loads that can be manually added by operator action are 1274 KW for diesel generator 11 and 1572 KW for diesel generator 12. Therefore, the total loads both automatically sequenced on and manually added by operator action are 6048 KW for diesel generator 11 and 5861 KW for diesel generator 12. The continous rating for Diesel Generators 11 and 12 is 7000 KW. Therefore, the maximum possible LOCA load that could be placed on Diesel Generator 11 represents 86.4% of continuous rating, while that on Diesel Generator 12 represents 83.7% of continous rating. The proposed Technical Specification change conservatively requires testing of Diesel Generator 11 and 12 per Technical Specification 4.8.1.1.2.a.5 to 90% of continuous rating.

For diesel generator 13 the correct total LOCA load is shown on FSAR Table 8.3-3 as 2953 KW. The continous rating for Diesel Generator 13 is 3300 KW. The total LOCA load therefore, represents 89.5% of continous rating. The proposed Technical Specification change conservatively requires testing of Diesel Generator 13 per Technical Specification 4.8.1.1.2.a.5 to 95% of continous load rating.

Specification 4.8.1.1.2.d.9 presently requires diesel generator testing on an 18 month frequency to consist of running the diesel for 24 hours. The first two hours of this test, the diesel generators are loaded to 110% of continuous rating and for the remaining 22 hours they are loaded at 100% of continuous rating. The proposed Technical Specification change requires loading the Diesel Generators 11 and 12 to 100% of

continous rating for the first 2 hours of the test and 90% of continous rating for the remaining 22 hours. These loadings correspond to 116% and 104%, respectively, of the maximum total LOCA loads for Diesel Generator 11; and 119% and 107%, respectively, for Diesel Generator 12. The proposed Technical Specification change also requires loading Diesel Generator 13 to 105% of continous rating for the first 2 hours of the test and to 95% of continous rating the remaining 22 hours. These loadings correspond to 117% and 106%, respectively of the maximum total LOCA load for Diesel Generator 13. The diesel generator loading for the 18 month test would then be as follows:

	First 2 Hours			Remaining 22 Hours		
Diesel Generator	% Of Maximum LOCA Load	% Of Continous Ratings	KW	% Of Maximum LOCA Load	% Of Continous Ratings	KW
11	116	100	7000	104	90	6300
12	119	100	7000	107	90	6300
13	117	105	3465	106	95	3125

JUSTIFICATION: The diesel generators at Grand Gulf have load carrying capacity in excess of that which is required for a LOCA with loss of offsite power. The capacity of the diesel generators is also in excess of those loads that are automatically sequenced on during a LOCA with loss of offsite power plus those loads that an operator could manually place on the diesel generators. Testing the diesel generators to ensure load carrying capability in excess of the maximum potential load meets the intent of Regulatory Guide 1.108. Testing to demonstrate load capabilities significantly in excess of the most severe loading for the diesel generators following the LOCA and loss of offsite power could cause degradation of the system due to wear on the equipment brought about by unnecessarily exceeding the continuous rating. This potential degration could decrease the availability of the diesel generators.

Using FSAR Tables 8.3-1, 8.3-2 and 8.3-3 to determine loads for a LOCA adds a measure of conservatism to the calculations. Most of the loads in the tables are from manufacturers nameplate data and do not reflect actual bus loads. The actual bus loads determined during startup were generally much lower than nameplate ratings.

The proposed changes accurately reflect testing that will demonstrate operability of the diesel generators in regard to maximum accident loading.

SIGNIFICANT HAZARDS CONSIDERATION:

The proposed Technical Specification changes increase the required loading on the diesel generators for the required 30 day test to levels consistent with the intent of Regulatory Guide 1.108. With respect to the 18 month test, the proposed changes require loadings, expressed as a precentage of the maximum LOCA plus loss of offsite power loads on the diesel generators, consistent with the intent of Regulatory Guide 1.108 while avoiding loading the diesel to levels which could potentially cause unnecessary wear. These Technical Specification changes, therefore, represent a modification to better reflect actual plant design, including diesel generator sizing, and to assure compliance with the intent of Regulatory Guide 1.108. There are no reductions in margin of safety. The probability or consequences of an accident previously evaluated is not increased nor is the possibility of a new or different kind of accident from any accident previously evaluated created. Thus the proposed change to the Technical Specification does not involve any significant hazards consideration.

NOTE: Technical Specification page changes marked with a PCOL number and circled are changes that were previously submitted to the NRC.

5. (GGNS-305745)

4.8.1.1.1 Each of the above required independent circuits between the offsite transmission network and the onsite Class 1E distribution system shall be:

a. Determined OPERABLE at least once per 7 days by verifying correct breaker alignments and indicated power availability, and

b. Demonstrated OPERABLE at least once per 18 months during shutdown by transferring, manually ~~and automatically~~, unit power supply from the normal circuit to the alternate circuit.

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4.8.1.1.2 Each of the above required diesel generators shall be demonstrated OPERABLE:

a. In accordance with the frequency specified in Table 4.8.1.1.2-1 on a STAGGERED TEST BASIS by:

1. Verifying the fuel level in the day tank.

2. Verifying the fuel level in the fuel storage tank.

3. Verifying the fuel transfer pump starts and transfers fuel from the storage system to the day tank.

4. Verifying the diesel starts from ambient condition and accelerates to at least 441 rpm for diesel generators 11 and 12 and 882 rpm for diesel generator 13 in less than or equal to 10 seconds. The generator voltage and frequency shall be 4160 ± 416 volts and 60 ± 1.2 Hz within ~~12~~ 10 seconds after the start signal. The diesel generator shall be started for this test by using one of the following signals:

PCOL 83/05 301, 306, 348

a) Manual.

b) Simulated loss of offsite power by itself.

c) Simulated loss of offsite power in conjunction with an ESF actuation test signal.

d) An ESF actuation test signal by itself.

5. Verifying the diesel generator is synchronized, loaded to greater than or equal to ~~3500~~ 6300 kW for diesel generators 11 and 12 and 3135 ~~1650~~ kW for diesel generator 13 in less than or equal to 60 seconds, and operates with these loads for at least 60 minutes.

6. Verifying the diesel generator is aligned to provide standby power to the associated emergency busses.

7. Verifying the pressure in all diesel generator air start receivers to be greater than or equal to:

a) 160 psig for diesel generator 11 and 12, and

b) 175 psig for diesel generator 13.

b. At least once per 31 days and after each operation of the diesel where the period of operation was greater than or equal to 1 hour by checking for and removing accumulated water from the day fuel tanks.

5. (GGNS-305, 745)

SURVEILLANCE REQUIREMENTS (Continued)

9. Verifying the diesel generator operates for at least 24 hours. During the first 2 hours of this test, the diesel generator shall be loaded to greater than or equal to ~~7700~~ 7000 kW for diesel generators 11 and 12 and ~~3630~~ 3465 kW for diesel generator 13 and during the remaining 22 hours of this test, the diesel generator shall be loaded to ~~7000~~ 6300 kW for diesel generators 11 and 12 and ~~3300~~ 3135 kW for diesel generator 13. The generator voltage and frequency shall be 4160 ± 416 volts and 60 ± 1.2 Hz within ~~[illegible]~~ 10 seconds after the start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test. Within 5 minutes after completing this 24-hour test, perform Surveillance Requirement 4.8.1.1.2.d.~~4~~ 7.a).2) and b).2)*.

PCOL 83/05 301, 306, 348 PCOL 83/05 350

10. Verifying that the auto-connected loads to each diesel generator do not exceed the continuous rating of 7000 kW for diesel generators 11 and 12 and 3300 kW for diesel generator 13.

11. Verifying the diesel generator's capability to:

   a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power,

   b) Transfer its loads to the offsite power source, and

   c) Be restored to its standby status.

12. Verifying that with the diesel generator operating in a test mode and connected to its bus that a simulated ECCS actuation signal:

   a) For Divisions 1 and 2, overrides the test mode by returning the diesel generator to standby operation.

   b) For Division 3, overrides the test mode by bypassing the diesel generator automatic trips per Surveillance Requirement 4.8.1.1.2.d.8.b).

13. Verifying that with all diesel generator air start receivers pressurized to less than or equal to 256 psig and the compressors secured, the diesel generator starts at least 5 times from ambient conditions and accelerates to at least 441 rpm for diesel generators 11 and 12 and 882 rpm for diesel generator 13 in less than or equal to ~~[illegible]~~ 10 seconds.

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*If Surveillance Requirement 4.8.1.1.2.d.4.a)2) or b)2) are not satisfactorily completed, it is not necessary to repeat the preceding 24 hour test. Instead, the diesel generator may be operated at rated load for one hour or until operating temperatures have stabilized.

6. (GGNS - 366)

SUBJECT: Technical Specification 4.8.2.1.d.2.b, page 3/4 8-12.

DISCUSSION: Surveillance Requirement 4.8.2.1.d.2.b specifies the load profile which the 125 volt DC Division 2 battery system must be verified to be capable of supplying. The load profile in item b) of this requirement should be revised as follows:

b) Division 2

$\geq$ 427 amperes for the first 60 seconds
$\geq$ 186 amperes for the next 119 minutes
$\geq$ 357 amperes for the next 60 seconds
$\geq$ 186 amperes for the next 118 minutes
$\geq$ 243 amperes for the last 60 seconds

JUSTIFICATION: The 125 volt DC battery load requirements for Division 2 are specified in Table 8.3-7 of the Grand Gulf Nuclear Station Final Safety Analysis Report (FSAR). To correctly reflect the as built condition of the plant and the planned change in the Division 2 inverter to a new class IE inverter, the requirements in Table 8.3-7 will be revised in the FSAR to reflect the loads supplied from the 125 volt DC Division 2 battery system. The proposed changes to Surveillance Requirement 4.8.2.1.d.2.b reflect the correct 125 volt DC Division 2 battery load profile.

In all cases, except for the last 60 seconds of the loss of AC power transient, the revised load requirements are more severe than the requirements contained in the current Technical Specifications. MP&L has determined that the existing design of the 125 volt DC Division 2 battery system is sufficient to supply the new load profile. The Technical Specification Surveillance Requirements for the 125 volt DC Division 2 battery load profile should be revised as shown to accurately reflect the anticipated post LOCA load profile based upon the installed system loads. The Division 2 battery system will be tested to the new load profile prior to implementation of the proposed Technical Specification change.

INTERNAL INFORMATION:

Letter MPB-83/0201 provides the load profile for the 125 volt DC Division 1 and 2 battery systems based on the assumption of 100 percent utilization of the Division 1 and 2 Westinghouse inverters (1Y87 and 1Y88). The actual connected loads are 77 amps less than the values based on the assumption of 100 percent utilization of the inverters.

The actual connected loads for Division 1 will remain below the present Technical Specification load profile until such time that a total additional continuous load in excess of 11.4 amps is connected. As a result, no change is requested for Division 1.

The actual connected loads for Division 2 will be greater than the present Technical Specification load profile. As a result, a change is necessary for Division 2. The proposed Technical Specification change is based on the load profile for 100 percent utilization of the Division 2 Westinghouse inverters (i.e., the Division 2 Technical Specification load profile will be 77 amps higher than the actual connected loads). Division 2 will require testing at the new load profile prior to implementation of the proposed Technical Specification change.

SIGNIFICANT HAZARDS CONSIDERATION:

The proposed changes to the Division 2 DC load profile results in a more stringent Surveillance Requirement than that currently in the Technical Specifications. Therefore, these changes do not cause a significant increase in the probability or consequences of an accident previously evaluated nor do they create the possibility of a new or different kind of accident from any accident previously evaluated. These changes do not constitute a significant hazards consideration.

d. At least once per 18 months, during shutdown, by verifying that either:

1. The battery capacity is adequate to supply and maintain in OPERABLE status all of the actual emergency loads for 4 hours for Divisions 1 and 2 and 2 hours for Division 3 when the battery is subjected to a battery service test, or

2. The battery capacity is adequate to supply a dummy load of the following profile, which is verified to be greater than the actual emergency load, while maintaining the battery terminal voltage greater than or equal to 105 volts.

a) Division 1

≥950 amperes for the first 60 seconds
≥128 amperes for the next 119 minutes
≥306 amperes for the next 60 seconds
≥128 amperes for the next 118 minutes
≥416 amperes for the last 60 seconds

b) Division 2

≥ 427 ~~≥395~~ amperes for the first 60 seconds
≥ 186 ~~≥66~~ amperes for the next 119 minutes
≥ 357 ~~≥244~~ amperes for the next 60 seconds
≥ 186 ~~≥66~~ amperes for the next 118 minutes
≥ 243 ~~≥244~~ amperes for the last 60 seconds

c) Division 3

≥76 amperes for the first 60 seconds
≥16 amperes for the next 59 minutes
≥18 amperes for the last 60 minutes

e. At least once per 60 months during shutdown by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test. Once per 60 month interval, this performance discharge test may be performed in lieu of the battery service test.

f. Annual performance discharge tests of battery capacity shall be given to any battery that shows signs of degradation or has reached 85% of the service life expected for the application. Degradation is indicated when the battery capacity drops more than 10% of rated capacity from its average on previous performance tests, or is below 90% of the manufacturer's rating.

7. (GGNS - 414)

SUBJECT: Technical Specification 4.3.4.2.3, page 3/4 3-39 and BASES page B3/4 3-3.

DISCUSSION: Technical Specification 4.3.4.2.3 presently requires verification at least once per sixty (60) months of the time allotted for breaker arc suppression, 50 milliseconds (msec).

This 50 msec value was incorrectly referred to in the Technical Specifications as the time "allotted for breaker arc suppression". This 50 msec time interval is the breaker interrupting time which consists of:

- The time delay from energization of the breaker trip coil to opening of the breaker contacts (35-45 msec) and,

- The time delay from opening of the breaker contacts to complete suppression of the electric arc (i.e., breaker arc suppression time, 4-12 msec).

The proposed change would delete the requirement in 4.3.4.2.3 to verify the 50 msec time allotted for breaker arc suppression at least once per 60 months, and would correct the BASES to reflect the appropriate breaker arc suppression time of 12 msec. A change would also be made to indicate the basis for the new proposed Surveillance Requirement 4.3.4.2.4 which verifies that no degradation has occurred above the time allotted for breaker arc suppression of 12 msec.

Surveillance Requirement 4.3.4.2.4 will require inspection and preventive maintenance, including a high potential test, on the breaker vacuum interrupter in accordance with the manufacturer's recommendation to verify that no degradation has occurred above the 12 msec time allotted for breaker arc suppression.

The proposed change to the BASES information in regard to the EOC-RPT system response time clarifies that the 190 msec response time is the total time from initiation of valve motion to complete suppression of the breaker electric arc. The 12 msec breaker arc suppression time and basis for verifying that no degration has occurred in the arc suppression time is also provided.

JUSTIFICATION: The proposed change will correct the specification and bases to accurately reflect the breaker arc suppression requirement. The vendor (General Electric) has performed design and production testing on this type of breaker (GE Model VB-7.2-500-12A "Power Vac") and has determined that, if periodic high potential testing of the vacuum interrupters is satisfactory, the design value of the breaker arc suppression

time is still valid. Thus, adding the breaker arc suppression time (12 msec) to the EOC-RPT system response time (190 msec) measured from initial valve motion to opening of the breaker main contacts results in determination of the total response time per the associated Technical Specification definition. The proposed change to the BASES will clarify the statement concerning the elements included in the EOC-RPT system response time to be consistent with the Definition 1.13 for this response time.

INTERNAL INFORMATION:

Vendor data also has shown a negligible time delay between opening of the main breaker contacts and opening of the auxiliary contacts. The auxiliary contacts provide a convenient measuring point.

SIGNIFICANT HAZARDS CONSIDERATION:

The proposed changes to Technical Specification 4.3.4.2.3 and Bases page B3/4 3-3 constitute a correction and clarification. The Technical Specification, as modified, will accurately reflect, and require testing to verify, the breaker arc suppression time requirement as well as the total system time response requirement. The vendor (General Electric) has performed design and production testing on this type of breaker (GE Model VB-7.2-500-12A "Power Vac") and has determined that, if periodic high potential testing of the vacuum interrupters is satisfactory, the design value of the breaker arc suppression time is still valid. Thus, adding the breaker arc suppression time (12 msec) to the EOC-RPT system response time measured from initial valve motion to opening of the breaker main contacts results in determination of the total response time (190 msec) per the associated Technical Specification definition. Therefore, this change to the Technical Specification and the associated Bases does not involve a significant reduction in margin of safety. Additionally, neither a significant increase in the probability or consequences of an accident previously evaluated nor the possibility of a new or a different kind of accident from the accident previously evaluated is involved. Therefore, this proposed change to the Technical Specification does not involve any significant hazards consideration.

NOTE: Technical Specification page changes marked with a PCOL number and circled are changes that were previously submitted to the NRC.

7. (GGNS-414)

SURVEILLANCE REQUIREMENTS

4.3.4.2.1 Each end-of-cycle recirculation pump trip system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.4.2.1-1.

4.3.4.2.2. LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months.

4.3.4.2.3 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of each trip function shown in Table 3.4.2-3 shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested at least once per 36 months. ~~The time allotted for breaker arc suppression, 50 ms, shall be verified at least once per 60 months~~.

4.3.4.2.4 AT LEAST ONCE PER 60 MONTHS EACH END-OF-CYCLE RECIRCULATION PUMP TRIP CIRCUIT BREAKER SHALL BE SUBJECTED TO INSPECTION AND PREVENTIVE MAINTENANCE TO INCLUDE A HIGH POTENTIAL TEST ON THE VACUUM INTERRUPTER IN ACCORDANCE WITH THE MANUFACTURER'S RECOMMENDATIONS TO VERIFY THAT NO DEGRADATION HAS OCCURRED ABOVE THE TIME ALLOTTED FOR BREAKER ARC SUPPRESSION, 12MSEC.

The time allotted for breaker arc suppression, 12 msec, was obtained from manufacturers design test data. Zero degradation in this breaker arc suppression time is verified over the useful life of the breaker as long as vacuum interrupter high potential tests are satisfactory.

7. (GGNS -414)

RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a closure sensor for each of two turbine stop valves provides input to one EOC-RPT system; a closure sensor from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 40% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, i.e., 190 ms~~, less the time allotted from start of motion of the stop valve or turbine control valve until the sensor relay contact supplying the input to the reactor protection system opens, i.e., 70 ms, and less the time allotted for breaker arc suppression determined by test, as correlated to manufacturer's test results, i.e., 50 ms, and plant pre-operational test results.~~

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or greater ~~less~~ than the drift allowance assumed for each trip in the safety analyses.

PCOL 83/06 450

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without providing actuation of any of the emergency core cooling equipment.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or greater ~~less~~ than the drift allowance assumed for each trip in the safety analyses.

PCOL 83/06 450

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or greater ~~less~~ than the drift allowance assumed for each trip in the safety analyses.

PCOL 83/06 450

8. (GGNS - 577)

SUBJECT: Technical Specification Tables 3.3.2-1.2.e and 4.3.2.1-1.2.e, pages 3/4 3-10, 3/4 3-14, and 3/4 3-23.

DISCUSSION: Technical Specification Table 4.3.2.1-1 item 2.e, Condenser Vacuum-Low, requires surveillance tests to be performed in OPERATIONAL CONDITIONS 1, 2**, and 3**. The "**" note requires the surveillances for OPERATIONAL CONDITIONS 2 and 3 to be performed when reactor steam pressure is greater than or equal to 1045 psig and/or any turbine stop valve is open. Specification 3.4.6.2 requires reactor steam dome pressure to be less than 1045 psig for OPERATIONAL CONDITIONS 1 and 2. The "**" note on Table 4.3.2.1-1 is in conflict with the requirements of specification 3.4.6.2 for OPERATIONAL CONDITION 2. There is no interlock on the Condenser Vacuum Low Trip function, therefore, this trip function may be manually bypassed regardless of turbine stop valve position. The proposed change will remove the exceptions to performing the Surveillance Requirements on the Condenser Vacuum - Low trip function in OPERATIONAL CONDITIONS 2 and 3. The proposed "**" note to table 4.3.2.1-1 should read as follows:

> "** The low condenser vacuum MSIV closure may be manually bypassed when condenser vacuum is below the Trip Setpoint to allow opening the MSIV's during reactor shutdown or for reactor startup. The manual bypass will be removed when condenser vacuum exceeds the Trip Setpoint."

The proposed "**" note specifies in the Technical Specifications the limits on bypassing the condenser vacuum-low MSIV Trip Setpoint and ensures that the trip function is in place when needed for Group 1 valve isolation.

For consistency, the proposed change adds the new "**" note to the Condenser Vacuum - Low trip function on Table 3.3.2-1. The new "**" note would apply to OPERATIONAL CONDITIONS 2 and 3 for the Condenser Vacuum - Low Trip Function on Table 3.3.2-1.

JUSTIFICATION: The present "**" note on Table 4.3.2.1-1 is in conflict with specification 3.4.6.2 concerning maximum reactor steam dome pressure in OPERATIONAL CONDITION 2. The proposed change will remove the exceptions (only when reactor steam dome pressure is greater than 1045 psig and/or turbine stop valves are open in OPERATIONAL CONDITIONS 2 and 3) to performing the Surveillance Requirements on the Condenser Vacuum - Low Trip function in OPERATIONAL CONDITIONS 2 and 3.

The proposed change will specify when the condenser vacuum - low MSIV trip function can be bypassed and when this trip function must be in operation to perform its design intent.

SIGNIFICANT HAZARDS CONSIDERATION:

The proposed change to the Technical Specification removes exceptions to performing the Surveillance Requirements on the Condenser Vacuum - Low Main Steam Line Isolation trip function. In addition, a requirement is added which assures that the manual by-pass of this trip function is removed when the Trip Setpoint is exceeded so that the design function of this feature is properly enabled. As these changes constitute additional restrictions not presently included in the Technical Specification, they do not involve any significant hazards considerations.

NOTE: Technical Specification page changes marked with a PCOL number and circled are changes that were previously submitted to the NRC.

TABLE 3.3.2-1

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
1. **PRIMARY CONTAINMENT ISOLATION**				
a. Reactor Vessel Water Level- Low Low, Level 2	6, 7, 8, 10(c)(d)	2	1, 2, 3 and #	20
b. Drywell Pressure - High	5, 6, 7, 9(c)(d)	2	1, 2, 3	20
c. Containment and Drywell Ventilation Exhaust Radiation - High High	7	2(e)	1, 2, 3 and *	21
d. Manual Initiation	5, 6, 7, 8, 9, 10	2~~/group~~	1, 2, 3 and *#	22
2. **MAIN STEAM LINE ISOLATION**				
a. Reactor Vessel Water Level- Low Low Low, Level 1	1, 5	2	1, 2, 3	20
b. Main Steam Line Radiation - High	1, 10(f)	2 ~~1/line~~	1, 2, 3	23
c. Main Steam Line Pressure - Low	1	2 ~~1/line~~	1	24
d. Main Steam Line Flow - High	1	2~~/line~~(g)	1, 2, 3	23
e. Condenser Vacuum - Low	1	2	1, 2, 3**#	23
f. Main Steam Line Tunnel Temperature - High	1	2	1, 2, 3	23
g. Main Steam Line Tunnel Δ Temp.- High	1	2	1, 2, 3	23
h. Manual Initiation	1, 5, 10	2~~/group~~	1, 2, 3	22

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8. (GGNS-782, 577)

INSTRUMENTATION

8. { GGNS- 782, 577, 97, 203, 261, 360, 381, 389, 390, 392, 436, 444, 505, 720, 721 }

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

ACTION

ACTION 20 - Be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

ACTION 21 - Close the affected system isolation valve(s) within one hour or:

a. In OPERATIONAL CONDITION 1, 2, or 3, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In Operational Condition *, suspend primary CORE ALTERATIONS, handling of irradiated fuel in the containment and operations with a potential for draining the reactor vessel.

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ACTION 22 - Restore the manual initiation function to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION 23 - Be in at least STARTUP with the associated isolation valves closed within 6 hours or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

ACTION 24 - Be in at least STARTUP within 6 hours.

ACTION 25 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within one hour.

ACTION 26 - Restore the manual initiation function to OPERABLE status within 8 hours or close the affected system isolation valves within the next hour and declare the affected system inoperable.

ACTION 27 - Close the affected system isolation valves within one hour and declare the affected system inoperable.

ACTION 28 - Lock the affected system isolation valves closed within one hour and declare the affected system inoperable.

** See Insert "A"

NOTES

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* When handling irradiated fuel in the primary or secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

\# During CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

(a) See Specification 3.6.4, Table 3.6.4-1 for valves in each valve group.

(b) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition provided at least one other OPERABLE channel in the same trip system is monitoring that parameter.

(c) Also actuates the standby gas treatment system.

(d) Also actuates the control room emergency filtration system in the isolation mode of operation.

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(e) ~~One upscale and/or two downscale actuate the trip system.~~ Two upscale Hi-Hi, one upscale Hi-Hi and one downscale, or two downscale signals from the same trip system actuate the trip system and initiate isolation of the associated containment and drywell isolation valves.

(f) Also trips and isolates the mechanical vacuum pumps.

(g) A channel is OPERABLE if 2 of 4 instruments in that channel are OPERABLE.

INSERT "B"

(h) Also actuates secondary containment ventilation isolation dampers and valves per Table 3.6.6.2-1.

(i) Closes only RWCU system ~~inlet outboard~~ isolation valve(s) G33-F004, G33-F001, & G33-F251

(j) Actuates the Standby Gas Treatment System and isolates Auxiliary Building penetrations of the ventilation systems within the Auxiliary Building

PCOL 83/08 375, 470

INSERT "C" →

(INSERT "A") INSERT TO PAGE 3/4 3-14

** The low condenser vacuum MSIV closure may be manually bypassed when condenser vacuum is below the trip setpoint to allow opening the MSIV's during reactor shutdown or for reactor startup. The manual bypass will be removed when condenser vacuum exceeds the trip setpoint.

(INSERT "B")

EACH TRIP SYSTEM MUST HAVE AT LEAST ONE INSTRUMENT PER MAIN STEAM LINE OPERABLE IN ORDER FOR THE CHANNELS TO BE CONSIDERED OPERABLE.

(INSERT "C")

(k) VALVES E12-F037A & E12-F037B ARE CLOSED BY HIGH DRYWELL PRESSURE. ALL OTHER GROUP 3 VALVES ARE CLOSED BY HIGH REACTOR PRESSURE.

(l) CLOSES ONLY RCIC OUTBOARD VALUES. A CONCURRENT RCIC INITIATION SIGNAL IS REQUIRED FOR ISOLATION TO OCCUR.

{GGNS - 782, 577, 97, 203, 261, 360, 381, 389, 390, 392, 436, 444, 505, 720, 721.}

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
6. RHR SYSTEM ISOLATION				
a. RHR Equipment Room Ambient Temperature - High	S	M	R	1, 2, 3
b. RHR Equipment Room Δ Temp. - High	S	M	R	1, 2, 3
c. Reactor Vessel Water Level - Low, Level 3	S	M	R	1, 2, 3
d. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	S	M	R	1, 2, 3
e. Drywell Pressure - High	S	M	R	1, 2, 3
f. Manual Initiation	NA	M(a)	NA	1, 2, 3

*When handling irradiated fuel in the primary or secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

~~**When reactor steam pressure > 1045 psig and/or any turbine stop valve is open.~~

#During CORE ALTERATION and operations with a potential for draining the reactor vessel.

(a) Manual initiation switches shall be tested at least once per 18 months during shutdown. All other circuitry associated with manual initiation shall receive a CHANNEL FUNCTIONAL TEST at least once per 31 days as part of circuitry required to be tested for automatic system isolation.

(b) Each train or logic channel shall be tested at least every other 31 days.

** The low condenser vacuum MSIV closure may be manually bypassed when condenser vacuum is below the trip setpoint to allow opening the MSIV's during reactor shutdown or for reactor startup. The manual bypass will be removed when condenser vacuum exceeds the trip setpoint.

PCOL 83/08 569, 322

8. (GGNS-577)

9. (GGNS - 583)

SUBJECT: Technical Specification 4.1.3.2.b, page 3/4 1-7.

DISCUSSION: Specification 4.1.3.2.b requires demonstration of maximum insertion time of control rods through measurement with reactor coolant pressure greater than or equal to 950 psig for specifically affected individual control rods following maintenance on or modification to the control rod or control rod drive system which could affect the scram insertion time of those specific control rods. The requirement is in conflict with Specification 4.0.4, which requires the surveillance to be completed prior to entering the OPERATIONAL CONDITIONS for the Limiting Condition for Operation. Entry into OPERATIONAL CONDITION 2 should be allowed to scram time test those rods that have had maintenance or modifications that could affect scram insertion times.

JUSTIFICATION: In order to perform the surveillance requirements of Specification 4.1.3.2.b, reactor coolant pressure must be greater than or equal to 950 psig. This proposed change will allow the reactor to enter OPERATIONAL CONDITION 2 and obtain greater than or equal to 950 psig to meet testing requirements. Entry into OPERATIONAL CONDITION 1 would still be prohibited until the applicable surveillance requirements have been met and the operability of the control rods or control rod drive system has been demonstrated.

SIGNIFICANT HAZARDS CONSIDERATION:

The proposed change relaxes the provisions of Specification 4.0.4 so that the plant conditions necessary to satisfy the intent of Technical Specification 4.1.3.2.b can be achieved. The Standard Technical Specifications in several areas indicates it is acceptable to relax the provisions of Specification 4.0.4 so that an OPERATIONAL CONDITION can be entered to achieve the plant conditions necessary to satisfy the intent of surveillance requirements. Therefore this change to the Technical Specification does not involve a significant reduction in a margin of safety. Additionally, as this change allows for the satisfaction of the intent of the surveillance, neither a significant increase in the probability or consequences of an accident previously evaluated nor the possibility of a new or different kind of accident from any accident previously evaluated is involved. Therefore, this proposed change to the Technical Specifications does not involve any significant hazards considerations.

NOTE: Technical Specification page changes marked with a PCOL number and circled are changes that were previously submitted to the NRC.

9. (GGNS-583)

LIMITING CONDITION FOR OPERATION (Continued)

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ACTION: (Continued)

b. With a "slow" control rod(s) not satisfying ACTION a.1, above:

   1. Declare the "slow" control rod(s) inoperable, and

   2. Perform the Surveillance Requirements of Specification 4.1.3.2.c at least once per 60 days when operation is continued with three or more "slow" control rods declared inoperable.

   Otherwise, be in at least HOT SHUTDOWN within 12 hours.

c. With the maximum scram insertion time of one or more control rods exceeding the maximum scram insertion time limits of Specification 3.1.3.2 as determined by Specification 4.1.3.2.c, operation may continue provided that:

   1. "Slow" control rods, i.e., those which exceed the limits of Specification 3.1.3.2, do not make up more than 20% of the 10% sample of control rods tested.

   2. Each of these "slow" control rods satisfies the limits of ACTION a.1.

   3. The eight adjacent control rods surrounding each "slow" control rod are:

      a) Demonstrated through measurement within 12 hours to satisfy the maximum scram insertion time limits of Specification 3.1.3.2, and

      b) OPERABLE.

   4. The total number of "slow" control rods, as determined by Specification 3.1.3.2.c, when added to the sum of ACTION a.3, as determined by Specification 4.1.3.2.a and b, does not exceed 7.

   Otherwise, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.2 The maximum insertion time of the control rods shall be demonstrated through measurement with reactor coolant pressure greater than or equal to 950 psig and, during single control rod scram time tests, the control rod drive pumps isolated from the accumulators:

a. For all control rods prior to THERMAL POWER exceeding 40% of RATED THERMAL POWER following CORE ALTERATIONS* or after a reactor shutdown that is greater than 120 days,

b. For specifically affected individual control rods** following maintenance on or modification to the control rod or control rod drive system which could affect the scram insertion time of those specific control rods, and

c. For at least 10% of the control rods, on a rotating basis, at least once per 120 days of POWER OPERATION.

*Except movement of SRM, IRM, or special removable detectors or normal control rod movement.

** The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDIDITION 2 provided this surveillance is completed prior to entry into OPERATIONAL CONDITION 1.

10. (GGNS - 723)

SUBJECT: Technical Specification Table 3.3.7.1-1, pages 3/4 3-56 and 3/4 3-58.

DISCUSSION: The present Table 3.3.7.1-1.6 requires a minimum of 2 channels OPERABLE for the control room ventilation radiation monitor. The proposed change increases the Minimum Operable Channels to 2 per trip system. There are four channels of radiation monitors for the control room ventilation system. Two of these channels supply signals to parallel contacts (both must open or 2 out of 2) to isolate control room ventilation and start Control Room Emergency Filtration Unit A. The other two channels supply signals to parallel contacts (both must open or 2 out of 2) to isolate control room ventilation and start Control Room Emergency Filtration Unit B. With only the present 2 channels required to be OPERABLE, it is possible to have one or both of the Standby Filtration Units inoperable. Action 73.a on Table 3.3.7.1-1 should be changed to reflect that with one monitor in a trip system inoperable the required action applies and may require at least one of the Control Room Emergency Filtration Systems to be operated in the isolation mode. Action 73.b on Table 3.3.7.1-1 should be changed to state that with both monitors in a trip system inoperable, at least one Control Room Emergency Filtration System will be placed in the isolation mode of operation within one hour.

JUSTIFICATION: Increasing the Minimum Operable Channels to 2 per trip system for the control room ventilation radiation monitor ensures adequate trip signals to the control room ventilation system and start signals to the control room Standby Filtration Units for maintaining system operability. These changes in the Action Statements are made to reflect the increase in Minimum Operable Channels to 2 per trip system and to ensure operability of the Control Room Emergency Filtration System.

SIGNIFICANT HAZARDS CONSIDERATION:

By increasing the minimum number of control room ventilation radiation monitors from 2 to 4, the present margin of safety is increased with respect to assuring control room isolation in the event it is required. In addition, because the new operability requirement is more stringent than the requirements in the current Technical Specification the change does not involve a significant increase in the probability or consequences of an accident which has been previously evaluated, nor does it create the possibility of a new or different kind of accident from any accident previously evaluated. Therefore, the proposed change to the Technical Specifications does not involve any significant hazards considerations.

NOTE: Technical Specification page changes marked with a PCOL number and circled are changes that were previously submitted to the NRC.

TABLE 3.3.7.1-1

RADIATION MONITORING INSTRUMENTATION

INSTRUMENTATION	MINIMUM CHANNELS OPERABLE	APPLICABLE CONDITIONS	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
1. Component Cooling Water Radiation Monitor	1	At all times	$\leq 1 \times 10^5$ cpm/NA	~~1~~ 10 to 10^6 cpm	70
2. Standby Service Water System Radiation Monitor	1/heat exchanger train	1, 2, 3, and*	$\leq 1 \times 10^5$ cpm/NA	~~1~~ 10 to 10^6 cpm	70
3. Offgas Pre-treatment Radiation Monitor	1	1, 2, and ###	$\leq 5 \times 10^3$ mR/hr/NA	1 to 10^6 mR/hr	~~70~~ 76
4. Offgas Post-treatment ~~Radiation~~ Monitor a. Noble Gas Activity, Providing Alarm and Automatic Termination of Release	2(a)	1, 2, and ##	$\leq 1 \times 10^5$ cpm (Hi), $\leq 1.0 \times 10^6$ cpm (Hi Hi)	~~1~~ 10 to 10^6 cpm	71
5. Carbon Bed Vault Radiation Monitor	1	1, 2	< 2 x full power background/NA	1 to 10^6 mR/hr	72
6. Control Room Ventilation Radiation Monitor	2 per Trip System	1,2,3,5 and**	≤4 mR/hr/ ≤5 mR/hr#	10^{-2} to 10^2 mR/hr	73
7. Containment and Drywell Ventilation Exhaust Radiation Monitor	3(a)h	At all times	≤2.0 mR/hr/ ≤4 mR/hr(b)#	10^{-2} to 10^2 mR/hr	74
8. Fuel Handling Area Ventilation Exhaust Radiation Monitor	3(a)h	1,2,3,5 and**	≤ 2mR/hr/ ≤4 mR/hr(d)#	10^{-2} to 10^2 mR/hr	75
9. Fuel Handling Area Pool Sweep Exhaust Radiation Monitor	3(a)h	(c)	≤ 18 mR/hr/ ≤35 mR/hr(d)#	10^{-2} to 10^2 mR/hr	75

PCOL 83/03 256

PCOL 83/03 256

10. (GGNS-697, 723)

PCOL 83/08 528

PCOL 83/08 528

PCOL 83/08 528

10. (GGNS-697, 723)

TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

ACTION

ACTION 70 - With the required monitor inoperable, obtain and analyze at least one grab sample of the monitored parameter at least once per 24 hours.

ACTION 71 -

a. With one of the required monitors inoperable, place the inoperable channel in the downscale tripped condition within one hour.

b. With both of the required monitors inoperable, ~~be in at least HOT SHUTDOWN within 12 hours.~~ effluent releases via this pathway may continue for up to 30 days provided grab samples are taken at least once per 8 hours and these samples are analyzed for gross activity within 24 hours

ACTION 72- With the required monitor inoperable, perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

ACTION 73 -

a. With one of the required monitors in a trip system inoperable, place the inoperable channel in the downscale tripped condition within one hour; restore the inoperable channel to OPERABLE status within 7 days, or, within the next 6 hours, initiate and maintain operation of ~~the~~ at least one control room emergency filtration system in the isolation mode of operation.

b. With both of the required monitors in a trip system inoperable, initiate and maintain operation of ~~the~~ at least one control room emergency filtration system in the isolation mode of operation within one hour.

ACTION 74 -

a. With one of the required monitors inoperable, place the inoperable channel in the downscale tripped condition within one hour.

b. With two of the required monitors inoperable, isolate the containment and drywell purge and vent penetrations within 12 hours.

ACTION 75 -

a. With one of the required monitors inoperable, place the inoperable channel in the downscale tripped condition within one hour.

b. With two of the required monitors inoperable, initiate and maintain operation of at least one standby gas treatment subsystem within 12 hours.

ACTION 76- With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, the recombiner effluent may be released to the environment for up to 72 hours provided:

a. At least one grab sample of the monitored parameter is obtained and analyzed at least once per 24 hours, and

b. The offgas system is not bypassed, except for filtration system bypass during plant start ups, and

c. The offgas post-treatment noble gas activity monitor is OPERABLE; otherwise, be in at least Hot Standby within 12 hours.

11. (GGNS - 718)

SUBJECT: Technical Specification 4.5.1.c.2.b, page 3/4 5-5

DISCUSSION: Surveillance Requirement 4.5.1.c.2.b presently indicates that the header differential pressure (delta P) instrumentation setpoint is 1.2 ± 0.1 psid change from the normal indicated delta P for the HPCS system, LPCS system, and the LPCI subsystems. The proposed Technical Specification change will correct this setpoint to less than or equal to 9.7 psid.

JUSTIFICATION: The proposed Technical Specification change will correct the header differential pressure instrumentation setpoint to a differential pressure change of less than or equal to 9.7 psid from the normal indicated differential pressure for the HPCS system, LPCS system, and the LPCI subsystems. For each of these systems (or subsystems), the header differential pressure instrumentation senses the differential pressure between that injection line and one of the other ECCS injection lines (headers) to the reactor vessel.

During normal plant operation, each header delta P signal should be zero. A break in a system injection line will result in the pressure in that line being less than the pressure in the unbroken line. As a result, the differential pressure between the broken injection line and the unbroken line will provide indication of a break in the system piping internal to the reactor vessel. The system design specification indicates an alarm shall be activated by delta P changes of 10 psid. The instrument setpoint is established to be less than or equal to 9.7 psid. This setpoint is sufficiently close to the normal differential pressure (0 psi) to ensure a broken line is detected, and yet provides a realistic band between the normal operating conditions and the instrumentation setpoint.

SIGNIFICANT HAZARDS CONSIDERATION:

The change to the Technical Specification is proposed to achieve consistency between the Technical Specification and the system design specification by increasing the header differential pressure instrumentation setpoint from 1.2 ± 0.1 psid to less than or equal to 9.7 psid. The design function of this instrumentation is to detect a break in a system injection line. The new setpoint is sufficiently close to the normal differential pressure to ensure a broken line will be detected, provides sufficient margin to minimize the probability of spurious actuation yet remains below the Allowable Value provided in the system design specification. Therefore the change will not significantly reduce a margin of safety. Further, as the intent of the surveillance requirement remains unchanged, it does not involve a significant increase in the

probability or consequences of an accident previously evaluated nor is the possibility created for a new or different kind of accident from any accident previously evaluated. Therefore the proposed change to the Technical Specification does not involve any significant hazards considerations.

11. (GGNS-718, 769)

SURVEILLANCE REQUIREMENTS (Continued)

2) Low pressure setpoint of the:

(a) LPCI A and B subsystem loop to be ≥ ~~30~~ 34 psig.

(b) LPCI C subsystem loop and LPCS system to be ≥ 22 psig.

(c) HPCS system to be ≥ 18 psig.

b) Header delta P instrumentation and verifying the setpoint of the HPCS system and LPCS system and LPCI subsystems to be ~~1.2 ± 0.1~~ ≤9.7 psid change from the normal indicated ΔP.

3. Verifying that the suction for the HPCS system is automatically transferred from the condensate storage tank to the suppression pool on a condensate storage tank low water level signal and on a suppression pool high water level signal.

d. For the ADS at least once per 18 months by:

1. Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

2. Manually opening each ADS valve when the reactor steam dome pressure is greater than or equal to 100 psig* and observing that either:

a) The control valve or bypass valve position responds accordingly, or

b) There is a corresponding change in the measured steam flow.

*The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test.

12. (GGNS - 743)

SUBJECT: Technical Specification 4.8.4.2.1.a, page 3/4 8-39.

DISCUSSION: The proposed change to Surveillance Requirement 4.8.4.2.1.a would delete the present 4.8.4.2.1.a and replace it with a new 4.8.4.2.1.a.1 and .2. This change would provide for surveillance of the thermal overloads which are normally in force during plant operation and bypassed under accident conditions by a CHANNEL FUNCTIONAL TEST of the individual valve overload protection bypass circuitry once per 92 days and of the entire channel once per 18 months.

JUSTIFICATION: This change to the specification involves only the 3 valves whose thermal overload protection is normally in force and is bypassed during accident conditions (Standby Service Water System (P41) valves, SP41-F154, F155A and F155B). The proposed testing of the individual valve bypass circuitry would test from the LOCA initiation contact in the P41 system to the valve overload to ensure that the overload is bypassed on an accident condition. This surveillance would be done every 92 days and would not interfere with normal plant operation.

Testing of the entire channel from the initiation of the accident signal through the bypass of the valve thermal overload protection would be covered by the 18 month ECCS instrumentation surveillance which tests the portion of the circuit from the LOCA transmitters to the LPCS initiation logic, the 18 month diesel surveillance which tests the portion of the circuit from the LPCS initiation logic to the SSW initiation logic and the surveillance which satisfies the 92 day requirement.

The present 4.8.4.2.1.a would require injection of a simulated signal into the LOCA signal transmitter as part of the CHANNEL FUNCTIONAL TEST once per 92 days. The portion of the logic from the LOCA signal transmitter to the relay contact in the associated valve thermal overload protection bypass circuitry is tested every 18 months. The 18 month surveillance is sufficient to demonstrate OPERABILITY of this portion of the logic in conjunction with the other functions in the Technical Specification which this portion of the logic performs. The proposed change would specify the 18 month test to demonstrate OPERABILITY of this portion of the logic to be consistent with other Surveillance Requirements in the specification instead of requiring a 92 day testing interval. The proposed change will continue to verify at a 92 day interval the OPERABILITY of the individual valve bypass circuitry from the LOCA contact through the overload bypass circuitry.

SIGNIFICANT HAZARDS CONSIDERATION:

This change is administrative in nature as it establishes consistency in surveillance philosphy with respect to individual circuitry and channel OPERABILITY. The proposed Channel Functional Test change assures OPERABILITY of thermal overload protection circuitry from the signal transmitter to the overload bypass circuitry. Thus no significant reduction in safety margin is created. Based upon this evaluation, no significant hazards considerations are involved.

12. (GGNS-743)

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

LIMITING CONDITION FOR OPERATION

3.8.4.2 The thermal overload protection of each valve shown in Table 3.8.4.2-1 shall be OPERABLE or shall be bypassed either continuously or only under accident conditions, as indicated, by an OPERABLE bypass device.

APPLICABILITY: Whenever the motor operated valve is required to be OPERABLE.

ACTION:

With the thermal overload protection for one or more of the above required valves not OPERABLE or not bypassed either continuously or only under accident conditions, as indicated in Table 3.8.4.2-1, take administrative action to bypass the thermal overload within 8 hours or declare the affected valve(s) inoperable and apply the appropriate ACTION statement(s) for the affected system(s).

SURVEILLANCE REQUIREMENTS

4.8.4.2.1 The thermal overload protection which is bypassed either continuously or only under accident conditions for the above required valves shall be verified to be bypassed continuously or only under accident conditions, as applicable, by an OPERABLE bypass device (1) by the performance of a CHANNEL FUNCTIONAL TEST of the bypass circuitry for those thermal overloads which are normally in force during plant operation and bypassed under accident conditions and (2) by verifying that the thermal overload protection is bypassed for those thermal overloads which are continuously bypassed and temporarily placed in force only when the valve motors are undergoing periodic or maintenance testing:

a. ~~At least once per 92 days f~~For those thermal overloads which are normally in force during plant operation and bypassed under accident conditions: 1. At least once per 92 days for the individual valve bypass circuitry.
2. At least once per 18 months for the entire channel.

b. At least once per 18 months for those thermal overloads which are continuously bypassed and temporarily placed in force only when the valve motors are undergoing periodic or maintenance testing.

c. Following maintenance on the motor starter.

4.8.4.2.2 The thermal overload protection which is not bypassed for the above required valves shall be demonstrated OPERABLE at least once per 18 months by the performance of a CHANNEL CALIBRATION of a representative sample of at least 25% of all thermal overloads for the above required valves.

4.8.4.2.3 The thermal overload protection for the above required valves which is continuously bypassed and temporarily placed in force only when the valve motor is undergoing periodic or maintenance testing shall be verified to be bypassed following periodic or maintenance testing during which the thermal overload protection was temporarily placed in force.

13. (GGNS - 759)

SUBJECT: Technical Specification Table 4.3.7.5-1, page 3/4 3-72.

DISCUSSION: Table 4.3.7.5-1 contains accident monitoring instrumentation Surveillance Requirements. The containment/drywell area radiation monitors are required to have a CHANNEL CALIBRATION every refueling outage. The radiation monitors are required by NUREG-0737 to have a range of 1 rad/hr to 10^8 rad/hr (beta and gamma) or alternatively 1R/hr to 10^7 R/hr (gamma only). Calibration onsite by use of a radiation source is impractical due to the range of the instrument and the size of the source required. NUREG-0737, Table II. F.1-3, allows in situ calibration by electronic signal substitution for all range decades above 10 R/hr provided that calibration for at least one decade below 10 R/hr is by means of a calibrated radiation source. The proposed Technical Specification change is to add the following "*" note to the CHANNEL CALIBRATION frequency for the containment/drywell area radiation accident monitoring instrumentation.

> "* Calibration will be accomplished by electronic signal substitution over the entire range, and by means of a calibrated radiation source between 1 R/hr and 10 R/hr."

JUSTIFICATION: NUREG-0737, Table II F.1-3, states that for high-range calibration, no adequate sources exist, so an alternative was provided. This alternative is in situ calibration by electronic substitution for all range decades above 10 R/hr and calibration for at least one decade below 10 R/hr by means of a calibrated radiation source. This proposed change to the Technical Specification notes the NUREG-0737 provisions for high-range radiation monitor calibration.

SIGNIFICANT HAZARDS CONSIDERATION:

The proposed change specifies an alternate method for calibration of the containment/drywell area radiation monitors which is consistent with NUREG-0737. This change does not alter the intent of the Surveillance Requirement of the specification. It therefore does not significantly increase the probability of consequences of a previously evaluated accident or create the possibility of a new or different kind of accident from any accident previously evaluated. Also, it does not significantly reduce the margin of safety. Therefore, the proposed change to the Technical Specifications does not involve any significant hazards considerations.

C55sp23

13. (GGNS-759, 546)

TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

	INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1.	Reactor Vessel Pressure	M	R
2.	Reactor Vessel Water Level	M	R
3.	Suppression Pool Water Level	M	R
4.	Suppression Pool Water Temperature	M	R
5.	Drywell/Containment Differential Pressure	M	R
6.	Drywell Pressure	M	R
7.	Drywell and Control Rod Cavity Temperature	M	R
8.	Containment Hydrogen Concentration Analyzer and Monitor	NA	M ~~Q*~~
9.	Drywell Hydrogen Concentration Analyzer and Monitor	NA	M ~~Q*~~
10.	Containment Pressure	M	R
11.	Containment Air Temperature	M	R
12.	Safety/Relief Valve Tail Pipe Pressure Switch Position Indicators	M	R
13.	Containment/Drywell Area Monitors	M	R*
14.	Containment Ventilation Monitor	M	R
15.	Off-gas and Radwaste Bldg. Ventilation Monitor	M	R
16.	Fuel Handling Area Ventilation Monitor	M	R
17.	Turbine Bldg. Ventilation Monitor	M	R
18.	Standby Gas Treatment System A & B Exhaust Monitors	M	R

~~*Using sample gas containing:~~

~~a. One volume percent hydrogen, remainder nitrogen.~~
~~b. Four volume percent hydrogen, remainder nitrogen.~~

*CALIBRATION WILL BE ACCOMPLISHED BY ELECTRONIC SIGNAL SUBSTITUTION OVER THE ENTIRE RANGE, AND BY MEANS OF A CALIBRATED RADIATION SOURCE BETWEEN 1 R/HR AND 10R/HR.

14. (GGNS - 546)

SUBJECT: Technical Specification Table 4.3.7.5-1, page 3/4 3-72.

DISCUSSION: Table 4.3.7.5-1 lists the accident monitoring instrumentation surveillance requirements including requirements for the containment and drywell hydrogen concentration analyzers and monitors. The present channel calibration frequency for these monitors is quarterly. The proposed change would make the channel calibration occur on a monthly frequency. Table 4.3.7.5-1 presently contains a "*" note that applies to the containment and drywell hydrogen concentration analyzers and monitors. The present note requires channel calibration using a sample gas containing one volume percent hydrogen (remainder nitrogen) for low level, and four volume percent hydrogen (remainder nitrogen) for high level calibration. The proposed change is to delete the "*" note from Table 4.3.7.5-1.

JUSTIFICATION: The vendor for the containment and drywell concentration analyzers and monitors recommends a monthly frequency for channel calibration. This increased frequency is based on instrument drift and will ensure that instrument readings stay within drift tolerances specified by the vendor. The instrument vendor also recommends a sample gas containing 3.5% to 10% hydrogen in nitrogen calibration gas. The present "*" note on Table 4.3.7.5-5 does not apply to the instruments being used at Grand Gulf and should be deleted.

SIGNIFICANT HAZARDS CONSIDERATION:

The proposed change to the calibration frequency of the containment and drywell hydrogen concentration analyzers and monitors constitutes an additional limitation by increasing the calibration frequency from the present quarterly to monthly. The deletion of the "*" note from Table 4.3.7.5-1 should be considered an administrative change that deletes information not applicable to the instrumentation at Grand Gulf. The containment and drywell hydrogen concentration analyzers and monitors will be calibrated using a sample gas that meets the vendor recommendations. This change does not involve the reduction of safety margins and no significant increase in the probability or consequences of an accident previously evaluated is involved nor is the possibility of a new or different kind of accident from any accident previously evaluated created. Thus the proposed changes to the Technical Specifications does not involve any significant hazards considerations.

(GGNS-759, 546)

TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Reactor Vessel Pressure	M	R
2. Reactor Vessel Water Level	M	R
3. Suppression Pool Water Level	M	R
4. Suppression Pool Water Temperature	M	R
5. Drywell/Containment Differential Pressure	M	R
6. Drywell Pressure	M	R
7. Drywell and Control Rod Cavity Temperature	M	R
8. Containment Hydrogen Concentration Analyzer and Monitor	NA	M ~~Q*~~
9. Drywell Hydrogen Concentration Analyzer and Monitor	NA	M ~~Q*~~
10. Containment Pressure	M	R
11. Containment Air Temperature	M	R
12. Safety/Relief Valve Tail Pipe Pressure Switch Position Indicators	M	R
13. Containment/Drywell Area Monitors	M	R*
14. Containment Ventilation Monitor	M	R
15. Off-gas and Radwaste Bldg. Ventilation Monitor	M	R
16. Fuel Handling Area Ventilation Monitor	M	R
17. Turbine Bldg. Ventilation Monitor	M	R
18. Standby Gas Treatment System A & B Exhaust Monitors	M	R

~~*Using sample gas containing:~~

~~a. One volume percent hydrogen, remainder nitrogen.~~
~~b. Four volume percent hydrogen, remainder nitrogen.~~

*CALIBRATION WILL BE ACCOMPLISHED BY ELECTRONIC SIGNAL SUBSTITUTION OVER THE ENTIRE RANGE, AND BY MEANS OF A CALIBRATED RADIATION SOURCE BETWEEN 1R/HR AND 10R/HR.

15. (GGNS - 769)

SUBJECT: Technical Specification 4.5.1.c.2.a.2.a, page 3/4 5-5.

DISCUSSION: Surveillance Requirement 4.5.1.c.2.a.2.a presently requires a channel calibration at least once per 18 months to verify the low pressure setpoint of the Low Pressure Coolant Injection (LPCI) A and B subsystem loop (keep fill) to be greater than or equal to 38 psig. The proposed change is to require the LPCI A and B subsystem loops to be greater than or equal to 34 psig.

JUSTIFICATION: The low pressure setpoint of the LPCI A and B subsystem loops is calculated considering the accuracy of the instrument loop, the elevation of the centerline of the pressure transmitter and the jockey pumps, and the high point elevation of the system. General Electric Design Specification Data Sheet Document 22A3139AK, Revision 5, ECN-NH14467 states that the Allowable Value for pressure indicating switch E12-PIS-N553A&B is given as the high point elevation in the system (centerline of F028A-A for LPCI A subsystem and centerline of F028B-B for LPCI B subsystem) with reference to transmitter zero at 0 psig at the low point of the system (centerline of the jockey pump). The Allowable Value at the high point in the system is calculated to be 33.2 psig. General Electric recommends adding 5 psig to the Allowable Value at the high point in the system to obtain the nominal trip setpoint. The Nominal Trip Setpoint would then be 33.2 psig plus 5 psig or approximately 38 psig. To determine the Allowable Value from the Trip Setpoint, instrument loop accuracy must be considered. Instrument loop accuracy was calculated using the manufacturer's device accuracies and is ±3.28 psig which was rounded off to ±4.0 psig. The Allowable Value is then 38±4 psig for a low end Technical Specification Allowable Value of greater than or equal to 34 psig.

During surveillance testing the LPCI subsystem (jockey) pump A was found to have a discharge pressure of 44 psig and the LPCI subsystem B pump to have a running discharge pressure of 46 psig. With the present setpoint of greater than or equal to 38 psig, adding on instrument loop inaccuracy, and considering small swings in subsystem pump discharge pressure, there is insufficient margin to prevent spurious alarms during normal operation. Thus the change to greater than or equal to 34 psig is warranted.

SIGNIFICANT HAZARDS CONSIDERATION:

The LPCI subsystem jockey pumps maintain their associated RHR pump discharge lines full of water to prevent water hammer damage to piping and to ensure RHR cooling at the earliest moment. Lowering the low pressure setpoint of the LPCI A and B subsystem loops to greater than or equal to 34 psig from 38 psig will still assure the subsystems perform their design function. The change to the setpoint takes into consideration

instrument loop accuracy, measured subsystem pump discharge pressure, elevations of subsystem pumps, system high point, and transmitters to calculate a new LPCI subsystem low pressure setpoint of greater than or equal to 34 psig. This change can be considered as a correction to the setpoint value for the low pressure setpoint of the LPCI A and B subsystem loops. This change does not involve a reduction of safety margins and no significant increase in the probability or consequences of an accident previously evaluated is involved nor is the possibility of a new or different kind of accident from any accident previously evaluated created. Thus the proposed change to the Technical Specifications does not involve any significant hazards consideration.

15. (GGNS-718, 769)

2) Low pressure setpoint of the:

(a) LPCI A and B subsystem loop to be ≥ ~~30~~ 34 psig.

(b) LPCI C subsystem loop and LPCS system to be ≥ 22 psig.

(c) HPCS system to be ≥ 18 psig.

b) Header delta P instrumentation and verifying the setpoint of the HPCS system and LPCS system and LPCI subsystems to be ~~1.2 ± 0.1~~ ≤9.7 psid change from the normal indicated ΔP.

3. Verifying that the suction for the HPCS system is automatically transferred from the condensate storage tank to the suppression pool on a condensate storage tank low water level signal and on a suppression pool high water level signal.

d. For the ADS at least once per 18 months by:

1. Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

2. Manually opening each ADS valve when the reactor steam dome pressure is greater than or equal to 100 psig* and observing that either:

a) The control valve or bypass valve position responds accordingly, or

b) There is a corresponding change in the measured steam flow.

*The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test.

16. (GGNS - 782)

SUBJECT: Technical Specification Tables 3.3.2-1, 3.3.3-1, and 3.3.7.5-1, pages 3/4 3-10 through 14, 3/4 3-25, and 3/4 3-70.

DISCUSSION: The proposed changes include corrections to some of the Minimum Operable Channels per Trip Function, Minimum Channels OPERABLE, and Required Number of Channels listed on the subject tables. The detailed changes are described and justifications provided below.

JUSTIFICATION: The following changes are proposed to Table 3.3.2-1:

1. For Primary Containment Isolation, Manual Initiation (1.d) change Minimum OPERABLE Channels per Trip System from "2/group" to "2". Grand Gulf has a pending design change to revise the manual initiation logic for Primary and Secondary Containment to require 2 pushbuttons each for outboard and for inboard isolation (i.e., 4 pushbuttons total). The power supply for Primary and Secondary Containment Isolation logic has been changed from Reactor Protection System (RPS) to the Static Inverters. The proposed logic change would prevent isolation from occurring when one division of RPS is de-energized, and make the isolation logic consistent with RWCU, RHR and Main Steam Line isolation as described in changes below (i.e., 4 pushbuttons total).

2. For the Main Steam Line Isolation, Section 2, change the following in the column for Minimum OPERABLE Channels per Trip System:

   a. Main Steam Line Radiation-High (2.b) and Main Steam Line Pressure-Low (2.c) change from "1/line" to "2". For these isolation functions, there are 4 instruments (each is a channel), one per each main steam line, and 2 instruments (channels) per trip system. To close the MSIV's requires 1 channel in each trip system and to close the other valves operated by these signals, 2 channels in each trip system are required. Therefore to perform isolation functions for all valves in the groups listed in 2.b and 2.c, two channels minimum per trip system are required to be OPERABLE and not 1 per line per trip system as presently stated in the Technical Specifications.

   b. Main Steam Line Flow-High (2.d) change from "2/line" to "2". There are 4 instruments (one for each main steam line) per channel, a total of 4 channels, and 2 channels/trip system for this function. To close the MSIVs requires 1 channel in each trip system and to

close the other valves in Group 1, 2 channels in each trip system are required. Therefore, to close all valves in Group 1, two channels minimum per trip system are required to be OPERABLE and not 2 per line per trip system as presently stated in the Technical Specifications. Also to clarify note (g) on page 3/4 3-14, add the following:

> "Each trip system must have at least 1 instrument per Main Steam Line OPERABLE in order for the channels to be considered OPERABLE."

c. Manual initiation change from "2/group" to "2". There are four pushbuttons that perform the manual initiation function. For the Main Steam Line Isolation Valves (MSIVs), 2 of the pushbuttons must be depressed to de-energize MSIV pilot solenoid A and 2 must be depressed to de-energize MSIV pilot solenoid B. Since both A&B pilot solenoids must be de-energized to close the MSIV's, 2 channels (pushbuttons) per trip system must be operable. For the other Main Steam Line Valves that are closed from these four manual initiation pushbuttons, 2 (per trip system) must be depressed to close outboard valves and 2 (per trip system) must be depressed to close inboard valves. Therefore, 2 channels (pushbuttons) per trip system are required. The present requirement of "2/group" is not correct.

3. In Secondary Containment Isolation Section 3, change manual initiation (3.e) from "1/group" to "2" in both places in the Minimum OPERABLE Channels per Trip System column. See the justification above for Primary Containment Isolation Manual Initiation, for a description of this change.

4. In Reactor Water Cleanup System Isolation Section 4 make the following changes to the Minimum OPERABLE channels per Trip System:

   a. Change Equipment Area Temperature - High (4.c) and Equipment Area delta Temperature - High from "1" to "1/room." This proposed change is made to clarify that each equipment area room initiates an isolation function.

   b. Change Manual Initiation (4.i) from "1/group" to "2". There are 4 pushbuttons that perform the Manual Initiation isolation function, 2 pushbuttons (channels) close the inboard valves and 2 close the outboard valves. Therefore, there are two trip systems each of which requires 2 pushbuttons (channels) to be OPERABLE.

5. For Reactor Core Isolation Cooling System (RCIC) Isolation, Section 5, change the following:

   a. Change RHR Equipment Room Ambient Temperature - High and RHR Equipment Room delta Temperature - High from "1" to "1/room" in the minimum OPERABLE channels per Trip System. This proposed change is made to clarify that each equipment area room initiates an isolation function.

   b. Change Manual Initiation (5.1) from "1/valve" to "1 (1)" for the minimum OPERABLE channels per trip system and add note (1) to valve group 4 and to page 3/4 3-14. This change clarifies that only one channel of manual initiation exists and only the RCIC outboard valves close unless a concurrent RCIC intiation signal is also present. This change reflects plant design and clarifies the manual initiation isolation function for RCIC.

6. In RHR System Isolation, Section 6, make the following changes in the minimum OPERABLE channels per trip system:

   a. Change RHR Equipment Room Ambient Temperature - High (6.a) and RHR Equipment Room delta Temperature - High (6.b) from "1" to "1/room." This proposed change is made to clarify that each equipment area room initiates an isolation function.

   b. Change Manual Initiation (6.f) from "1/group" to "2." There are 4 pushbuttons that perform the Manual initiation isolation function, 2 pushbuttons (channels) close the inboard valves and 2 close the outboard valves. Therefore, there are two trip systems each of which requires 2 pushbuttons (channels) to be OPERABLE.

The following changes are proposed to Table 3.3.3-1:

1. For LPCS Pump Discharge Pressure - High (A.2.e), LPCI Pump A Discharge Pressure - High (A.2.f) and LPCI Pump B and C Discharge Pressure - High (B.2.e) change the minimum OPERABLE channels per trip system from "1" to "2" for LPCS and LPCI A, and from "1/pump" to "2/pump" for LPCI B and C. Automatic Depressurization System (ADS) Trip System A design requires 2 pump running signals to actuate. These signals are one LPCI or one LPCS running <u>and</u> one LPCI or one LPCS pump running. The pump running signals come from the pump discharge pressure - high instrumentation. The

present Technical Specification requirement for minimum OPERABLE channels per trip function is one channel/pump. Since there are two channels available for each pump, one channel is presently allowed to be out of service. With one channel out of service, the ADS initiation signal for that pump is defeated.

The changes to Table 3.3.7.5-1 are made to clarify intent of the table on items 7 and 10. Item 7 is the Drywell and Control Rod Drive Cavity Temperature instrumentation. The Required Number of Channels has "(each)" added to ensure that 2 temperature instrument channels are required for both the Drywell and the Control Rod Drive Cavity. This change is also proposed for the minimum channels OPERABLE column for clarification purposes. Item 10 on the table is Containment Pressure. The proposed changes are to clarify that wide and narrow range instrumentation is involved and 2 of each is required for the Required Number of Channels and 1 of each is required for the minimum channels OPERABLE.

SIGNIFICANT HAZARDS CONSIDERATION:

The changes proposed to Tables 3.3.2-1, 3.3.3-1 and 3.3.7.5-1 are made to reflect actual system configuration, to correct errors and to add clarification. These changes are purely administrative in nature or constitute additional controls not presently included in the Technical Specifications. This change does not involve a reduction in the margin of safety nor does it involve a significant increase in the probability or consequences of an accident previously evaluated nor does it create the possibility of a new or different kind of accident from any accident previously evaluated. Therefore, this change does not constitute a significant hazards consideration.

TABLE 3.3.2-1

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
1. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level-Low Low, Level 2	6, 7, 8, 10(c)(d)	2	1, 2, 3 and #	20
b. Drywell Pressure - High	5, 6, 7, 9(c)(d)	2	1, 2, 3	20
c. Containment and Drywell Ventilation Exhaust Radiation - High High	7	2(e)	1, 2, 3 and *	21
d. Manual Initiation	5, 6, 7, 8, 9, 10	2~~/group~~	1, 2, 3 and *#	22
2. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level-Low Low Low, Level 1	1, 5	2	1, 2, 3	20
b. Main Steam Line Radiation - High	1, 10(f)	2 ~~1/line~~	1, 2, 3	23
c. Main Steam Line Pressure - Low	1	2 ~~1/line~~	1	24
d. Main Steam Line Flow - High	1	2~~/line~~(g)	1, 2, 3	23
e. Condenser Vacuum - Low	1	2	1, 2**, 3**	23
f. Main Steam Line Tunnel Temperature - High	1	2	1, 2, 3	23
g. Main Steam Line Tunnel Δ Temp.- High	1	2	1, 2, 3	23
h. Manual Initiation	1, 5, 10	2~~/group~~	1, 2, 3	22

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16. (GGNS-782, 577)

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
3. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level-Low Low, Level 2	6(c)(d)(h)	2	1, 2, 3, and #	25
b. Drywell Pressure - High	6(c)(d)(h)	2	1, 2, 3	25
c. Fuel Handling Area Ventilation Exhaust Radiation - High High	~~8(c)(h)~~ NA(j)	2	1, 2, 3, and *	25
d. Fuel Handling Area Pool Sweep Exhaust Radiation - High High	~~8(c)(h)~~ NA(j)	2	1, 2, 3, and *	25
e. Manual Initiation	6(f) 6(f)	2 ~~1/group~~ 2 ~~1/group~~	1, 2, 3 *	26 25
4. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. Δ Flow - High	8	1	1, 2, 3	27
b. Δ Flow Timer	8	1	1, 2, 3	27
c. Equipment Area Temperature - High	8	1/room	1, 2, 3	27
d. Equipment Area Δ Temp. - High	8	1/room	1, 2, 3	27
e. Reactor Vessel Water Level - Low Low, Level 2	8	2	1, 2, 3	27
f. Main Steam Line Tunnel Ambient Temperature - High	8	1	1, 2, 3	27
g. Main Steam Line Tunnel Δ Temp. - High	8	1	1, 2, 3	27
h. SLCS Initiation	8(i)	NA	1, 2, 3	27
i. Manual Initiation	8	2 ~~1/group~~	1, 2, 3	26

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16. (GGNS-782)

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Flow - High	4	1	1, 2, 3	27
b. RCIC Steam Supply Pressure - Low	4, 9	1	1, 2, 3	27
c. RCIC Turbine Exhaust Diaphragm Pressure - High	4	2	1, 2, 3	27
d. RCIC Equipment Room Ambient Temperature - High	4	1	1, 2, 3	27
e. RCIC Equipment Room Δ Temp. - High	4	1	1, 2, 3	27
f. Main Steam Line Tunnel Ambient Temperature - High	4	1	1, 2, 3	27
g. Main Steam Line Tunnel Δ Temp. - High	4	1	1, 2, 3	27
h. Main Steam Line Tunnel Temperature Timer	4	1	1, 2, 3	27
i. RHR Equipment Room Ambient Temperature - High	4	1/room	1, 2, 3	27
j. RHR Equipment Room Δ Temp. - High	4	1/room	1, 2, 3	27
k. RHR/RCIC Steam Line Flow - High	4	1	1, 2, 3	27
l. Manual Initiation	4 (l)	1~~/valve~~	1, 2, 3	26

16. {(GGNS-782, 97, 203, 261, 360, 381, 389, 390, 392, 436, 444, 505, 720, 721)}

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
6. RHR SYSTEM ISOLATION				
a. RHR Equipment Room Ambient Temperature - High	3	1/room	1, 2, 3	28
b. RHR Equipment Room Δ Temp. - High	3	1/room	1, 2, 3	28
c. Reactor Vessel Water Level - Low, Level 3	3	2	1, 2, 3	28
d. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	$3^{(k)}$	2	1, 2, 3	28
e. Drywell Pressure - High	$3^{(k)}$	2	1, 2, 3	28
f. Manual Initiation	3, 4	2 ~~1/group~~	1, 2, 3	26

16. {GGNS-782, 97, 203, 261, 360, 381, 389, 390, 392, 436, 444, 505, 720, 721.}

16 {GGNS-782, 577, 97, 203, 261, 360, 381, 389, 390, 392, 436, 444, 505, 720, 721}

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

ACTION

ACTION 20 - Be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

ACTION 21 - Close the affected system isolation valve(s) within one hour or:

a. In OPERATIONAL CONDITION 1, 2, or 3, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In Operational Condition *, suspend CORE ALTERATIONS, handling of irradiated fuel in the primary containment and operations with a potential for draining the reactor vessel.

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ACTION 22 - Restore the manual initiation function to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION 23 - Be in at least STARTUP with the associated isolation valves closed within 6 hours or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

ACTION 24 - Be in at least STARTUP within 6 hours.

ACTION 25 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within one hour.

ACTION 26 - Restore the manual initiation function to OPERABLE status within 8 hours or close the affected system isolation valves within the next hour and declare the affected system inoperable.

ACTION 27 - Close the affected system isolation valves within one hour and declare the affected system inoperable.

ACTION 28 - Lock the affected system isolation valves closed within one hour and declare the affected system inoperable.

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** See Insert "A"

NOTES

* When handling irradiated fuel in the primary or secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

\# During CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

(a) See Specification 3.6.4, Table 3.6.4-1 for valves in each valve group.

(b) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition provided at least one other OPERABLE channel in the same trip system is monitoring that parameter.

(c) Also actuates the standby gas treatment system.

(d) Also actuates the control room emergency filtration system in the isolation mode of operation.

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(e) ~~One upscale and/or two downscale actuate the trip system.~~ Two upscale Hi-Hi, one upscale ... two downscale signals from the same trip system actuate the trip system and initiate isolation of the associated containment and drywell isolation valves.

(f) Also trips and isolates the mechanical vacuum pumps.

(g) A channel is OPERABLE if 2 of 4 instruments in that channel are OPERABLE.

INSERT "B"

(h) Also actuates secondary containment ventilation isolation dampers and valves per Table 3.6.6.2-1.

(i) Closes only RWCU system ~~inlet outboard~~ isolation valves G33-F004, G33-F001, G33-F251

(j) Actuates the Standby Gas Treatment System and isolates Auxiliary Building penetrations of the ventilation systems within the Auxiliary Building

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INSERT "C"

(INSERT "A") INSERT TO PAGE 3/4 3-14

** The low condenser vacuum MSIV closure may be manually bypassed when condenser vacuum is below the trip setpoint to allow opening the MSIV's during reactor shutdown or for reactor startup. The manual bypass will be removed when condenser vacuum exceeds the trip setpoint.

(INSERT "B")

EACH TRIP SYSTEM MUST HAVE AT LEAST ONE INSTRUMENT PER MAIN STEAM LINE OPERABLE IN ORDER FOR THE CHANNELS TO BE CONSIDERED OPERABLE.

(INSERT "C")

(k) VALVES E12-F037A & E12-F037B ARE CLOSED BY HIGH DRYWELL PRESSURE. ALL OTHER GROUP 3 VALUES ARE CLOSED BY HIGH REACTOR PRESSURE.

(l) CLOSES ONLY RCIC OUTBOARD VALUES. A CONCURRENT RCIC INITIATION SIGNAL IS REQUIRED FOR ISOLATION TO OCCUR.

(GGNS - 782, 577, 97, 203, 261, 360, 381, 389, 390, 392, 436, 444, 505, 720, 721.)

TABLE 3.3.3-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION[a]	APPLICABLE OPERATIONAL CONDITIONS	ACTION
A. DIVISION I TRIP SYSTEM			
1. RHR-A (LPCI MODE) & LPCS SYSTEM			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2[b]	1, 2, 3, 4*, 5*	30
b. Drywell Pressure - High	2[b]	1, 2, 3	30
c. LPCI Pump A Start Time Delay Relay	1	1, 2, 3, 4*, 5*	31
d. Manual Initiation	1/system	1, 2, 3, 4*, 5*	32
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "A"#, ##			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2[b]	1, 2, 3	30
b. Drywell Pressure - High	2[b]	1, 2, 3	30
c. ADS Timer	1	1, 2, 3	31
d. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	31
e. LPCS Pump Discharge Pressure-High (Permissive)	~~1~~ 2	1, 2, 3	31
f. LPCI Pump A Discharge Pressure-High (Permissive)	~~1~~ 2	1, 2, 3	31
g. Manual Initiation	1/valve	1, 2, 3	32
B. DIVISION 2 TRIP SYSTEM			
1. RHR B & C (LPCI MODE)			
a. Reactor Vessel Water Level - Low, Low Low, Level 1	2[b]	1, 2, 3, 4*, 5*	30
b. Drywell Pressure - High	2[b]	1, 2, 3	30
c. LPCI Pump B Start Time Delay Relay	1	1, 2, 3, 4*, 5*	31
d. Manual Initiation	1/system	1, 2, 3, 4*, 5*	32
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "B"#, ##			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2[b]	1, 2, 3	30
b. Drywell Pressure - High	2[b]	1, 2, 3	30
c. ADS Timer	1	1, 2, 3	31
d. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	31
e. LPCI Pump B and C Discharge Pressure - High (Permissive)	2 ~~1~~/pump	1, 2, 3	31
f. Manual Initiation	1/valve	1, 2, 3	32

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(GGNS-782) 16.

TABLE 3.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	REQUIRED NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	ACTION
1. Reactor Vessel Pressure	2	1	80
2. Reactor Vessel Water Level	2	1	80
3. Suppression Pool Water Level	2	1	80
4. Suppression Pool Water Temperature	6, 1/sector	6, 1/sector	80
5. Drywell/Containment Differential Pressure	2	1	80
6. Drywell Pressure	2	1	80
7. Drywell and Control Rod Drive Cavity Temperature	2 (each)	1 (each)	80
8. Containment Hydrogen Concentration Analyzer and Monitor	2	1	80
9. Drywell Hydrogen Concentration Analyzer and Monitor	2	1	80
10. Containment Pressure (wide and narrow range)	2 (each)	1 (each)	80
11. Containment Air Temperature	2	1	80
12. Safety/Relief Valve Tail Pipe Pressure Switch Position Indicators	1/valve	1/valve	80
13. Containment/Drywell Area Monitors	2#	1#	81
14. Containment Ventilation Monitor	1	1	81
15. Off-gas and Radwaste Bldg. Ventilation Monitor	1	1	81
16. Fuel Handling Area Ventilation Monitor	1	1	81
17. Turbine Bldg. Ventilation Monitor	1	1	81
18. Standby Gas Treatment System A & B Exhaust Monitors	1/each	1/each	81

16.(GGNS-782)

#Each for containment and drywell.

17. (GGNS - 786)

SUBJECT: Technical Specification 3.8.1.1.b.1.b, page 3/4 8-1.

DISCUSSION: Technical Specification 3.8.1.1.b.1.b currently requires a minimum level of 120 gallons for the Diesel Generator 13 day tank. A 220 gallon minimum limit is required for Diesel Generators 11 and 12. The 120 gallon minimum level required for Diesel Generator 13 is incorrect and should be increased to 220 gallons. The revised required minimum level for Diesel Generator 13 (220 gallons) is consistent with Technical Specification 3.8.1.2 which requires 220 gallons minimum for all three day tanks.

JUSTIFICATION: The proposed change will make Technical Specifications 3.8.i.1.b.1.b consistent with Technical Specification 3.8.1.2. This change is also conservative in that it increases the minimum quantity of fuel oil required to be available in the Diesel Generator 13 day tanks.

SIGNIFICANT HAZARDS CONSIDERATION:

The proposed change corrects an error in Technical Specification 3.8.1.1.b.1.b and achieves consistency with related Technical Specifications. The proposed change is also conservative with respect to the present requirement. Therefore, the change does not involve significant reductions in margins of safety nor does it increases the probability of or consequences of an accident previously evaluated nor the possibility of a new or different kind of accident from any accident previously evaluated. Therefore, this proposed change to the Technical Specifications does not involve any significant hazards consideration.

17. (GGNS-786)

3/4.8.1 A.C. SOURCES

A.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Three separate and independent diesel generators, each with:

1. Separate day fuel tanks containing a minimum of~~:~~

~~a)~~ 220 gallons of fuel ~~each for diesel generators 11 and 12, and~~

~~b) 120 gallons of fuel for diesel generator 13.~~

2. A separate fuel storage system containing a minimum of:

a) 48,000 gallons of fuel each for diesel generators 11 and 12, and

b) 39,000 gallons of fuel for diesel generator 13.

3. A separate fuel transfer pump.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With either one offsite circuit or diesel generator 11 or 12 of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirements 4.8.1.1.1.a within one hour and 4.8.1.1.2.a.4, for one diesel generator at a time, within three hours and at least once per 8 hours therafter; restore at least two offsite circuits and diesel generators 11 and 12 to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one offsite circuit and diesel generator 11 or 12 of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirements 4.8.1.1.1.a within one hour and 4.8.1.1.2.a.4, for one diesel generator at at time, within two hours and at least once per 8 hours thereafter; restore at least one of the inoperable A.C. sources to OPERABLE status within 12 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore at least two offsite circuits and diesel generators 11 and 12 to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

18. SUBJECT: Technical Specification Table 3.6.4-1, Section 1.a, page 3/4 6-30, Section 1.a, page 3/4 6-32, Section 3.a, page 3/4 6-38, and Section 3.a, page 3/4 6-40.

DISCUSSION: The proposed change to Technical Specification Table 3.6.4-1 would delete valves E12-F290A and E12-F290B from Section 1.a (Automatic Isolation Valves - Containment) and add them to Section 3.a (Other Isolation Valves - Containment). This change is proposed to support the implementation of a design change package (DCP) needed to correct a design deficiency. The subject DCP will remove the containment isolation signal from the minimum flow valves E12-F290A&B associated with the RHR jockey pumps (Trains A&B). Additional discussion is provided in Attachment 1.

JUSTIFICATION: Compliance with a design requirement to provide a continuous pressurized source of water to the main RHR pumps (Train A&B) and discharge piping cannot be assured with the existing logic that closes valves E12-F290A&B upon receipt of a containment isolation signal (high drywell pressure or RPV Level 2). Therefore, the proposed DCP will remove the isolation signal from the subject valves. The problem surfaces when the subject valves receive an RPV Level 2 signal to isolate when the Feedwater Leakage Control Valves E38-F001A&B (normally closed) are also shut. With both the minimum flow valve and the FWLC valve shut, the jockey pumps will trip automatically to prevent dead-heading. However, this feature has the undesirable effect of tripping the jockey pumps at RPV Level 2, whereas the main RHR pumps do not start until the RPV water level falls to Level 1. The pressurized source of water is removed during this time interval. With the automatic containment isolation signal removed from the subject valves, containment isolation will still be achieved and maintained. The jockey pump discharge pressure is higher than the containment design pressure; thus any leakage would be into the containment. Also, if the jockey pumps are not running the subject valves will close automatically isolating the containment. Additional information is provided as Attachment 1.

SIGNIFICANT HAZARDS CONSIDERATION:

The proposed change will support the implementation of a DCP to remove the automatic containment isolation signal from the RHR jockey pump. As discussed above, effective containment isolation will still be achieved and maintained with the removal of the isolation signal; thus the proposed change maintains a commensurate level of safety. This change does not involve a significant increase in the probability or consequences of an accident previously evaluated nor does it create the possibility of a new or different kind of accident from an accident previously evaluated. For these reasons, this proposed change does not constitute a significant hazards consideration.

ATTACHMENT 1

I. Background

In letter AECM-83/0243, dated April 15, 1983, MP&L notified the NRC Office of Inspection & Enforcement, Region II, of a Reportable Deficiency at the Grand Gulf Nuclear Station. The deficiency concerns the inability to maintain a continuous pressurized water supply to the main RHR pumps and discharge piping. In subsequent discussions with both the NRC I&E and NRR Staff, a design change was proposed to correct the subject deficiency by preventing the automatic tripping of the jockey pumps due to minimum flow valve closure. The purpose of this attachment to the proposed Technical Specification Table 3.6.4-1 is to describe the deficiency and to provide a detailed description of the proposed design change to correct the subject deficiency.

II. RHR Discharge Line Fill System Requirements

A requirement of the RHR system is that cooling water flow to the reactor pressure vessel (RPV) be initiated rapidly when the system is called on to perform its function. The lag between receipt of the signal to start the RHR pumps and the initiation of flow into the RPV can be minimized by keeping the discharge lines full. Additionally, if these lines were empty when the systems were actuated, the forces associated with the accelerating fluid into a dry pipe (water hammer) could cause physical damage to the piping and support. Thus, a design specification was established to provide a pressurized water supply that would ensure that the RHR pumps and discharge piping are filled continuously with water. To comply with this specification, the RHR jockey pump subsystem was designed, consisting of a jockey pump that takes suction from the corresponding RHR pump suction line from the suppression pool and discharges downstream of the check valve on the RHR pump discharge line.

III. Description of Current Jockey Pump Subsystem & Deficiency

The purpose of the RHR "A" & "B" train jockey pump subsystem is two-fold:

1. To provide a pressurized water supply to the RHR pumps and discharge piping, and

2. To supply the water necessary for the Feedwater Leakage Control System (FWLC).

The jockey pumps are rated at a differential pressure of 50 psi at a flow of 40 gpm to ensure that the RHR pump discharge piping remain full even with the maximum expected leakage rate through each boundary valve of the filled piping system. The maximum expected leakage rate for each filled train is less than 1 gpm. To prevent overheating the jockey pump, if the RHR discharge line valves do not leak, a minimum flow bypass line is provided to continuously circulate water back to the RHR pump suction lines or suppression pool.

The jockey pump logic was designed so that either the jockey pump minimum flow valve (E12-F290A&B) or the FWLC system supply valve (E38-F001A&B) must be open to allow jockey pump operation.

A simplified sketch of the jockey pump subsystem arrangement is provided in Figure 1 of this attachment. During normal operation, the FWLC supply valves are closed and the minimum flow valves are open to allow the jockey pumps to supply pressurized water to the RHR pumps and discharge piping. The minimum flow valves were provided with a containment isolation signal since the jockey pump discharge returns to a point downstream of the isolation valves (E12-F064A&B) in the RHR test return line.

The existing logic closes valves E12-F290A&B on a containment isolation signal (high drywell pressure or RPV Level 2). This will in turn trip the associated jockey pumps A & B if the FWLC control valves are also closed. The purpose of this feature is to prevent dead-heading the jockey pumps. However, it has the undesirable effect of tripping the jockey pumps at RPV Level 2, whereas the main RHR pumps do not automatically start until the RPV falls to Level 1. During this period of time the RHR discharge piping could become depressurized and partially drained. This condition would create a water hammer, during the RHR pump start, which could result in damage to the RHR piping, supports, and valves. This condition could create a safety hazard.

IV. Description of Proposed Design Change

The proposed design change to correct the described deficiency will revise the logic for both the jockey pumps and their associated minimum flow valves. The principal changes are described as follows:

1. Removes the containment isolation signal from the minimum flow valves (E12-F290A&B).

2. Closes the minimum flow valve when the jockey pump is not running.

3. Opens the minimum flow valve when the jockey pump is running and the FWLC valve is closed.

Effective containment isolation is achieved, since the jockey pump discharge pressure is higher than the containment design pressure allowing any leakage to be into the containment. Also, when the jockey pump is inoperable, the minimum flow valve will close automatically to isolate the containment.

Implementation of the proposed design change package described above will correct the identified deficiency and assure that a pressurized source of water is provided to the RHR pump and discharge piping continuously.

RHR Jockey Pump Subsystem
Trains 'A' & 'B'

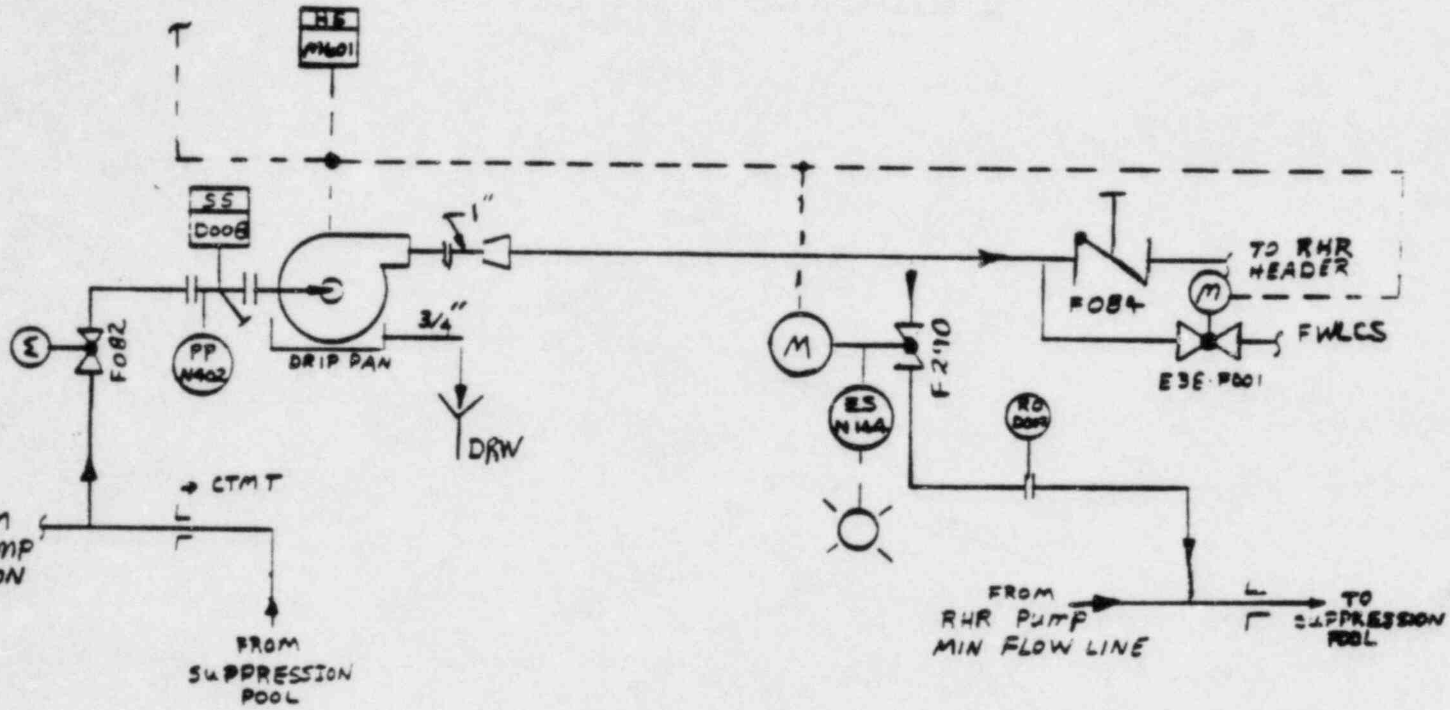

Figure 1

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER	VALVE GROUP[a]	MAXIMUM ISOLATION TIME (Seconds)
Containment (Continued)				
RHR Heat Exchanger "A" to LPCI	E12-F028A-A	20(I)[c]	5	78
RHR Heat Exchanger "A" to LPCI	E12-F037A-A	20(I)[c]	3	63
RHR Heat Exchanger "B" to LPCI	E12-F042B-B	21(I)[c]	5	22
RHR Heat Exchanger "B" to LPCI	E12-F028B-B	21(I)[c]	5	78
RHR Heat Exchanger "B" to LPCI	E12-F037B-B	21(I)[c]	3	63
RHR "A" Test Line to Supp. Pool	E12-F024A-A	23(O)[d]	5	93
RHR "A" Test Line to Supp. Pool	E12-F011A-A	23(O)[d]	5	27
~~RHR "A" Test Line to Supp. Pool~~	~~E12-F290A-A~~	~~23(O)~~[d]	~~6~~	~~8~~
RHR "C" Test Line to Supp. Pool	E12-F021B-B	24(O)[d]	5	101
HPCS Test Line	E22-F023-C	27(O)	6	60
RCIC Pump Suction	E51-F031-A	28(O)	4	38
RCIC Turbine Exhaust	E51-F077-A	29(O)[c]	9	18
LPCS Test Line	E21-F012-A	32(O)	5	101
Cont. Purge and Vent Air Supply	M41-F011	34(O)	7	4
Cont. Purge and Vent Air Supply	M41-F012	34(I)	7	4
Cont. Purge and and Vent Air Exh.	M41-F034	35(I)	7	4
Cont. Purge and and Vent Air Exh.	M41-F035	35(O)	7	4
Plant Service Water Return	P44-F070-B	36(I)	6	24
Plant Service Water Return	P44-F069-A	36(O)	6	24
Plant Service Water Supply	P44-F053-A	37(O)	6	24
Chilled Water Supply	P71-F150	38(O)	6	30
Chilled Water Return	P71-F148	39(O)	6	30

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER	VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (Seconds)
Containment (Continued)				
Comb. Gas Control Cont. Purge (Outside Air Supply)	E61-F009	65(O)	7	4
Comb. Gas Control Cont. Purge (Outside Air Supply)	E61-F010	65(I)	7	4
Purge Rad. Detector	E61-F056	66(I)	7	4
Purge Rad. Detector	E61-F057	66(O)	7	4
RHR "B" Test Line To Suppr. Pool	E12-F024B-B	67(O)[(d)]	5	93
RHR "B" Test Line To Suppr. Pool	E12-F011B-B	67(O)[(d)]	5	27
~~RHR "B" Test Line To Suppr. Pool~~	~~E12-F290B-B~~	~~67(O)[(d)]~~	~~6~~	~~8~~
Refueling Water Transf. Pump Suction	P11-F130	69(O)[(c)]	6	4
Refueling Water Transf. Pump Suction	P11-F131	69(O)[(c)]	6	4
Instr. Air to ADS	P53-F003-A	70(O)	6	4
RCIC Turbine Exh. Vacuum Breaker	E51-F078-B	75(O)	9	7
RWCU to Feedwater	G33-F040-B	83(I)	8	30
RWCU to Feedwater	G33-F039-A	83(O)	8	29
Chemical Waste Sump Discharge	P45-F098	84(I)	6	4
Chemical Waste Sump Discharge	P45-F099	84(O)	6	4
Supp. Pool Clean-up Return	P60-F009-A	85(O)	6	4
Supp. Pool Clean-up Return	P60-F010-B	85(O)	6	4
Demin. Water Supply to Cont.	P21-F017-A	86(O)	6	10
Demin. Water Supply to Cont.	P21-F018-B	86(I)	6	10
RWCU Pump Suction	G33-F001-B	87(I)	8	30

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Containment (Continued)		
RHR Heat Ex. "C" to LPCI	E12-F234	22(O)(c)
RHR Pump "C" to LPCI	E12-F041C-B	22(I)
RHR Pump "A" Test Line to Suppr. Pool	E12-F259	23(O)(e)
RHR Pump "A" Test Line to Suppr. Pool	E12-F261	23(O)(e)
RHR Pump "A" Test Line to Suppr. Pool	E12-F227	23(O)(e)
RHR Pump "A" Test Line to Suppr. Pool	E12-F252	23(O)(e)
RHR Pump "A" Test Line to Suppr. Pool	E12-F228	23(O)(e)
RHR Pump "A" Test Line to Suppr. Pool	E12-F338	23(O)(c)
RHR Pump "A" Test Line to Suppr. Pool	E12-F339	23(O)(c)
RHR Pump "A" Test Line to Suppr. Pool	E12-F260	23(O)(e)
RHR Pump "C" Test Line to Suppr. Pool	E12-F280	24(O)(e)
RHR Pump "C" Test Line to Suppr. Pool	E12-F281	24(O)(e)
HPCS Suction	E22-F014	25(O)(d)
HPCS Discharge	E22-F005	26(I)(c)
HPCS Discharge	E22-F218	26(I)(c)
HPCS Discharge	E22-F201	26(I)(c)
HPCS Test Line	E22-F035	27(O)(d)
HPCS Test Line	E22-F302	27(O)(e)
HPCS Test Line	E22-F301	27(O)(e)
LPCS Pump Suction	E21-F031	30(O)(d)
LPCS Discharge	E21-F006	31(I)(c)
LPCS Discharge	E21-F200	31(I)(c)
LPCS Discharge	E21-F207	31(I)(c)
LPCS Test Line	E21-F217	32(O)(e)
LPCS Test Line	E21-F218	32(O)(e)

Add
RHR "A" Test Line to Suppr. Pool E12-F290A-A 23(O)d

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Containment (Continued)		
RHR Pump "B" Test Line	E12-F213	67(O)(e)
RHR Pump "B" Test Line	E12-F249	67(O)(e)
RHR Pump "B" Test Line	E12-F250	67(O)(e)
RHR Pump "B" Test Line	E12-F334	67(O)(c)
RHR Pump "B" Test Line	E12-E335	67(O)(c)
Inst. Air to ADS	[illegible]-F006	70(I)
LPCS Relief Valve Vent Header	E2[illegible]F018	71A(O)(d)
RHR Pump "C" Relief Valve Vent Header	E12-F025C	71B(O)(d)
RHR Shutdown Vent Header	E12-F036	73(O)(d)
RHR Shutdown Suction Relief Valve Disch.	E12-F005	76B(O)(d)
RHR Heat Ex. "A" Relief Vent Header	E12-F055A	77(O)(d)
RHR Heat Ex. "A" Relief Vent Header	E12-F103A	77(O)(d)
RHR Heat Ex. "A" Relief Vent Header	E12-F104A	77(O)(d)
Cont. Leak Rate Sys.	NA	82(I)
SSW "A" Supply	P41-F169A	89(I)(c)
SSW "B" Supply	P41-F169B	92(I)(c)
Ctmt. Leak Rate Test Inst.	M61-F015	110A(O)
Ctmt. Leak Rate Test Inst.	M61-F014	110A(I)
Ctmt. Leak Rate Test Inst.	M61-F019	110C(O)
Ctmt. Leak Rate Test Inst.	M61-F018	110C(I)
Ctmt. Leak Rate Test Inst.	M61-F017	110F(O)
Ctmt. Leak Rate Test Inst.	M61-F016	110F(I)

Add RHR "B" Test Line to Suppr. Pool E12-F290B ~~B~~ 67(O)d