GEORGIA POWER COMPANY

OGLETHORPE POWER CORPORATION

MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA

CITY OF DALTON, GEORGIA

DOCKET NO. 50-321

EDWIN I. HATCH NUCLEAR PLANT, UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 103
License No. DPR-57

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

   A. The application for amendment by Georgia Power Company, et al., (the licensee) dated September 5, 1984, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. DPR-57 is hereby amended to read as follows:

Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No.103 , are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

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

FOR THE NUCLEAR REGULATORY COMMISSION

John F. Stolz

John F. Stolz, Chief
Operating Reactors Branch #4
Division of Licensing

Attachment:
Changes to the Technical
Specifications

Date of Issuance: December 7, 1984

ATTACHMENT TO LICENSE AMENDMENT NO. 103

FACILITY OPERATING LICENSE NO. DPR-57

DOCKET NO. 50-321

Replace the following pages of the Appendix "A" Technical Specifications with the enclosed pages. The revised pages are identified by Amendment number and contain a vertical line indicating the area of change.

Remove	Insert
1.0-6	1.0-6
1.1-3	1.1-3
1.1-4	1.1-4
1.1-5	1.1-5
1.1-13	1.1-13
1.1-14	1.1-14
Figure 2.1-1	Figure 2.1-1
1.2-1	1.2-1
1.2-2	1.2-2
1.2-4	1.2-4
1.2-6	1.2-6, 6a
3.1-3	3.1-3
3.1-4	3.1-4
3.1-5	3.1-5
3.1-7	3.1-7
3.1-8	3.1-8
3.1-11	3.1-11
3.1-12	3.1-12
3.1-13	3.1-13*
3.1-14	3.1-14
3.1-15	3.1-15
3.1-16	3.1-16*
3.1-17	3.1-17
3.1-18	3.1-18
3.2-1	3.2-1
3.2-2	3.2-2
3.2-5	3.2-5
3.2-8	3.2-8
3.2-10	3.2-10
3.2-11	3.2-11
3.2-13	3.2-13*
3.2-14	3.2-14
3.2-20	3.2-20
3.2-22	3.2-22
	3.2-23c
3.2-24	3.2-24
3.2-27	3.2-27
3.2-30	3.2-30
3.2-33	3.2-33
3.2-34	3.2-34*

*Overleaf page included for document completeness.

Remove	Insert
3.2-35	3.2-35
3.2-37	3.2-37*
3.2-38	3.2-38
3.2-45	3.2-45
--	3.2-49c
3.2-50	3.2-50, 50a
3.2-52	3.2-52
3.2-53	3.2-53
3.2-55	3.2-55
3.2-56	3.2-56
3.2-57	3.2-57
3.2-58	3.2-58
3.2-59	3.2-59
3.2-60	3.2-60
3.2-62	3.2-62
3.2-68a	3.2-68a
3.2-69	3.2-69
3.2-70	3.2-70*
3.6-9	3.6-9
3.6-9a	3.6-9a, 9b
3.6-21	3.6-21
3.6-22	3.6-22
3.7-17	3.7-17
3.7-18	3.7-18
3.7-19	3.7-19
3.7-20	3.7-20*
3.7-35	3.7-35
3.7-36	3.7-36*

GG. Simulated Automatic Actuation - Simulated automatic actuation means applying a simulated signal to the sensor to actuate the circuit in question.

HH. Start & Hot Standby Mode - The reactor is in the Start & Hot Standby Mode when the Mode Switch is in the START & HOT STANDBY position. In this mode the reactor protection system is energized with IRM and APRM (Start & Hot Standby Mode) neutron monitoring system trips and control rod withdrawal inter-locks in service.

II. Surveillance Frequency - Periodic surveillance tests, checks, calibrations, and examinations shall be performed within the specified surveillance intervals. These intervals may be adjusted plus or minus 25%. The operating cycle interval as pertaining to instrument and electrical surveillance shall never exceed 15 months. In the case where the elapsed interval has exceeded 100% of the specified interval, the next surveillance interval shall commence at the end of the original specified interval.

JJ. Surveillance Requirements - The surveillance requirements are requirements established to ensure that the Limiting Conditions for Operation as stated in Section 3 of these Technical Specifications are met. Surveillance requirements are not required on systems or parts of systems that are not required to be operable or are tripped. If tests are missed on parts not required to be operable or are tripped, then they shall be performed prior to returning the system to an operable status.

KK. Total Peaking Factor (TPF) - The total peaking factor is the highest product of radial, axial, and local peaking factors simultaneously operative at any segment of fuel rod.

LL. Transition Boiling - Transition boiling is the boiling that occurs between nucleate and film boiling. Transition boiling is manifested by an unstable fuel cladding surface temperature, rising suddenly as steam blanketing of the heat transfer surface occurs, then dropping as the steam blanket is swept away by the coolant flow, then rising again.

SAFETY LIMITS	LIMITING SAFETY SYSTEM SETTINGS

2.1.A.1.d. APRM Rod Block Trip Setting

The APRM rod block trip setting shall be:

$$S_{RB} \leq 0.66\ W + 42\%$$

where:

S_{RB} = Rod block setting in percent of rated thermal power (2436 MWt)

W = Loop recirculation flow rate in percent of rated (rated loop recirculation flow rate equals 34.2×10^6 lb/hr)

In the event of operation with a core maximum fraction of limiting power density (CMFLPD) greater than the fraction of rated core thermal power $(\frac{\text{Core MW Thermal}}{2436})$, the ARPM gain shall be adjusted up to 95% of rated thermal power as follows:

APRM Reading ≥ 100% x CMFLPD

Provided that the adjusted APRM reading does not exceed 100% of rated thermal power and the required gain adjustment increment does not exceed 10% of rated thermal power.

2. Reactor Vessel Water Low Level Scram Trip Setting (Level 3)

Reactor vessel water low level scram trip setting (Level 3) shall be ≥ 8.5 inches (narrow range scale).

3. Turbine Stop Valve Closure Scram

Turbine stop valve closure scram trip setting shall be ≤ 10 percent valve closure from full open. This scram is only effective when turbine steam flow is above 30% of rated, as measured by turbine first stage pressure.

2.1.A.4. Turbine Control Valve Fast Closure Scram Trip Setting

Turbine control valve fast closure scram trip shall initiate within 30 milliseconds of start of control valve fast closure. Fast closure is sensed by measuring electro-hydraulic control oil line pressure which decreases rapidly upon generator load rejection and just prior to fast closure of the control valves. This scram is only effective when turbine steam flow is above 30% of rated, as measured by turbine first stage pressure.

5. Main Steam Line Isolation Valve Closure Scram Trip Setting

Scram trip setting from main steam line isolation valve closure shall be ≤ 10 percent valve closure from full open. This scram is effective in the Run Mode.

6. Main Steam Line Isolation Valve Closure on Low Pressure

Main steam line isolation valve closure on low pressure at inlet to turbine valves shall occur at ≥ 825 psig, while in the Run Mode.

7. Main Steam Line Isolation Valve Closure on Low Condenser Vacuum

Main steam line isolation valve closure on low condenser vacuum shall occur at ≥ 7 inches Hg vacuum.

2.1.B. Reactor Vessel Water Level Trip Settings Which Initiate Core Standby Cooling Systems (CSCS)

Reactor vessel water level trip settings which initiate core standby cooling systems shall be as shown in Tables 3.2-2 thru 3.2-6 at normal operating conditions.

1. HPCI Actuation (Level 2)

   HPCI actuation (Level 2) shall occur at a water level ≥ -55 inches.

2. Core Spray and LPCI Actuation (Level 1)

   Core Spray and LPCI actuation (Level 1) shall occur at a water level ≥ -121.5 inches.

The APRM flow referenced scram trip setting at full recirculation flow is adjustable up to 120% of rated power. This reduced flow referenced trip setpoint will result in an earlier scram during slow thermal transients, such as the loss of 80°F feedwater heating event, than would result with the 120% fixed high neutron flux scram trip. The lower flow referenced scram setpoint therefore decreases the severity (ΔCPR) of a slow thermal transient and allows lower Operating Limits if such a transient is the limiting abnormal operational transient during a certain exposure interval in the cycle.

The APRM fixed high neutron flux signal does not incorporate the time constant, but responds directly to instantaneous neutron flux. This scram setpoint scrams the reactor during fast power increase transients if credit is not taken for a direct (position) scram, and also serves to scram the reactor if credit is not taken for the flow referenced scram.

The APRM reading must be adjusted to ensure that the LHGR transient peak is not increased for any combination of CMFLPD and reactor core thermal power. The APRM reading is adjusted in accordance with the formula in Specification 2.1.A.1.c., when the CMFLPD is greater than the fraction of rated core thermal power.

Analyses of the limiting transients show that no scram adjustment is required to assure MCPR > 1.07 when the transient is initiated from the operating MCPR limit.

d. APRM Rod Block Trip Setting

Reactor power level may be varied by moving control rods or by varying the recirculation flow rate. The APRM system provides a control rod block to prevent rod withdrawal beyond a given point at constant recirculation flow rate, and thus to protect against the condition of a MCPR less than 1.07. This rod block trip setting, which is automatically varied with recirculation loop flow rate, prevents an increase in the reactor power level to excessive values due to control rod withdrawal. The flow variable trip setting provides substantial margin from fuel damage, assuming a steady-state operation at the trip setting, over the entire recirculation flow range. The margin to the Safety Limit increases as the flow decreases for the specified trip setting versus flow relationship; therefore, the worst case MCPR which would occur during a steady-state operation is at 108% of rated thermal power because of the APRM rod block trip setting. The actual power distribution in the core is established by specified control rod sequences and is monitored continuously by the in-core LPRM system. The APRM reading is adjusted to compensate for a CMFLPD greater than the fraction of rated core thermal power.

2. Reactor Vessel Water Low Level Scram Trip Setting (Level 3)

The trip setting for low level scram is above the bottom of the separator skirt. This level is > 14 feet above the top of the active fuel. This level has been used in transient analyses dealing with coolant inventory decrease. The results reported in FSAR Section 14.3 show that a scram at this level adequately protects the fuel and the pressure barrier. The designated scram trip setting is at least 22 inches below the bottom of the normal operating range and is thus adequate to avoid spurious scrams.

2.1.A.3. Turbine Stop Valve Closure Scram Trip Settings

The turbine stop valve closure scram trip anticipates the pressure, neutron flux and heat flux increase that could result from rapid closure of the turbine stop valves. With a scram trip setting of ≤ 10 percent of valve closure from full open, the resultant increase in surface heat flux is limited such that MCPR remains above 1.07 during the worst case transient that assumes the turbine bypass is closed. This scram is bypassed when turbine steam flow is below 30% of rated, as measured by turbine first stage pressure.

4. Turbine Control Valve Fast Closure Scram Trip Setting

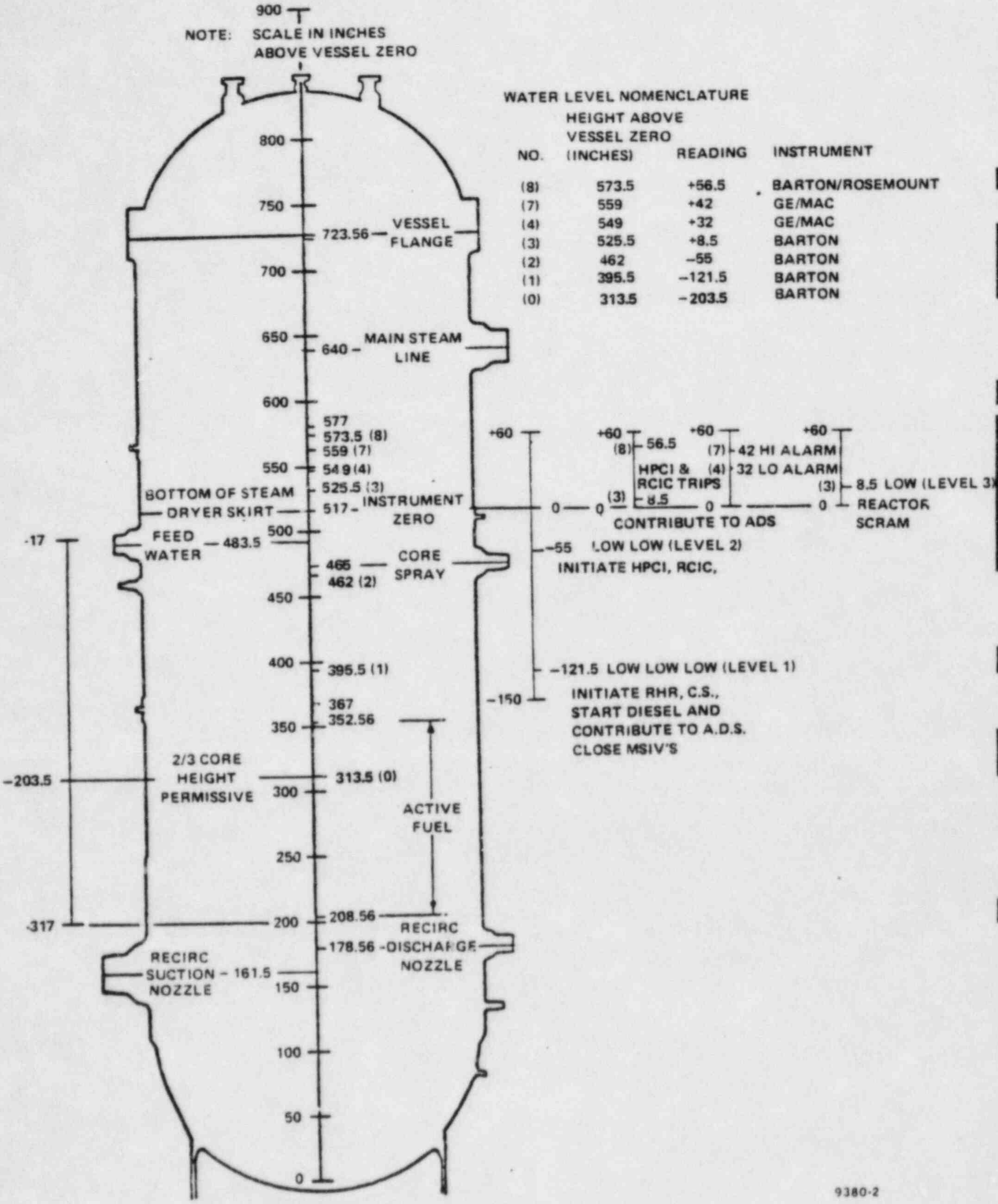
This turbine control valve fast closure scram anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection exceeding the capability of the turbine bypass. The Reactor Protection System initiates a scram when fast closure of the control valves is initiated by the fast acting solenoid valves. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic control oil pressure at the main turbine control valve actuator disc dump valves. This loss of pressure is sensed by pressure switches whose contacts form the one-out-of-two-twice logic input to the reactor protection system. This trip setting, a nominally 50% greater closure time and a different valve characteristic from that of the turbine stop valve, combine to produce transients very similar and no more severe than for the stop valve. This scram is bypassed when turbine steam flow is below 30% of rated, as measured by turbine first stage pressure.

5. Main Steam Line Isolation Valve Closure Scram Trip Setting

The main steam line isolation valve closure scram occurs within 10% of valve movement from the fully open position and thus anticipates the neutron flux and pressure scrams which remain as available backup protection. This scram function is bypassed automatically when the Mode Switch is not in the RUN position.

6. Main Steam Line Isolation Valve Closure on Low Pressure

The low pressure isolation of the main steam lines at 825 psig was provided to protect against rapid reactor depressurization and the resulting rapid cooldown of the vessel, which might result from a pressure regulator failure causing inadvertent opening of the control and/or bypass valves.



WATER LEVEL NOMENCLATURE

NO.	HEIGHT ABOVE VESSEL ZERO (INCHES)	READING	INSTRUMENT
(8)	573.5	+56.5	BARTON/ROSEMOUNT
(7)	559	+42	GE/MAC
(4)	549	+32	GE/MAC
(3)	525.5	+8.5	BARTON
(2)	462	−55	BARTON
(1)	395.5	−121.5	BARTON
(0)	313.5	−203.5	BARTON

FIGURE 2.1-1
REACTOR VESSEL WATER LEVEL

1.2 REACTOR COOLANT SYSTEM INTEGRITY

Applicability

The Safety Limit, established to preserve the reactor coolant system integrity, applies to the limit on the reactor vessel steam dome pressure.

Objective

The objective of the Safety Limit (associated with preserving the reactor coolant system integrity) is to establish a pressure limit below which the integrity of the reactor coolant system is not threatened due to any overpressure condition.

Specifications

A. Reactor Vessel Steam Dome Pressure

1. When Irradiated Fuel is in the Reactor

The reactor vessel steam dome pressure shall not exceed 1325 psig at any time when irradiated fuel is present in the reactor vessel.

2.2 REACTOR COOLANT SYSTEM INTEGRITY

Applicability

The Limiting Safety System Settings apply to trip settings of the instruments and devices which are provided to prevent the reactor vessel steam dome pressure Safety Limit from being exceeded.

Objective

The objective of the Limiting Safety System Settings is to define the level of the process variables at which automatic protective action is initiated to prevent the reactor vessel steam dome pressure Safety Limit from being exceeded.

Specifications

A. Nuclear System Pressure

1. When Irradiated Fuel is in the Reactor

When irradiated fuel is present in the reactor vessel, and the head is bolted to the vessel, the limiting safety system settings shall be as specified below:

Protective Action	Limiting Safety System Settings (psig)
a. Scram on high reactor pressure (reactor vessel steam dome pressure)	≤ 1054
b. Nuclear system relief valves open on nuclear system pressure	4 valves at 1080 4 valves at 1090 3 valves at 1100

2.2.A Nuclear System Pressure (cont.)

The allowable setpoint relief error for each valve shall be ± 1%. In the event that an installed safety-relief valve requires replacement, a spare valve whose setpoint is lower than that of the failed valve may be substituted for the failed valve until the first refueling outage following such substitution. No more than two valves with lower setpoints may be substituted in place of valves with higher setpoints. Spare valves which are used as substitutes under the abovementioned provisions shall have a setpoint equal to 1080 psig ±1% or 1090 psig ±1%.

1.2.A.2. When Operating The RHR System in the Shutdown Cooling Mode

The reactor vessel steam dome pressure shall not exceed 162 psig at any time when operating the RHR system in the Shutdown Cooling Mode.

2.2.A.2. When Operating The RHR System in the Shutdown Cooling Mode

The reactor pressure trip setting which closes (on increasing pressure) or permits opening (on decreasing pressure) of the shutdown cooling isolation valves shall be ≤ 135 psig.

1.2.A.2. When Operating the RHR System in the Shutdown Cooling Mode

The design pressure of the shutdown cooling piping of the Residual Heat Removal System is not exceeded with the reactor vessel steam dome pressure less than 162 psig.

2.2 REACTOR COOLANT SYSTEM INTEGRITY

A: Nuclear System Pressure

1. When Irradiated Fuel is in the Reactor

The 11 relief/safety valves are sized and set point pressures are established in accordance with the following requirements of Section III of the ASME Code:

a. The lowest relief/safety valve must be set to open at or below vessel design pressure and the highest relief/safety valve must be set to open at or below 105% of design pressure.

b. The valves must limit the reactor pressure to no more than 110% of design pressure.

The primary system relief/safety valves are sized to limit the primary system pressure, including transients, to the limits expressed in the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels. No credit is taken from a scram initiated directly from the isolation event, or for power operated relief/safety valves, sprays, or other power operated pressure relieving devices. Thus, the probability of failure of the turbine-generator trip SCRAM or main steam isolation valve closure SCRAM is conservatively assumed to be unity. Credit is taken for subsequent indirect protection system action such as neutron flux SCRAM and reactor high pressure SCRAM, as allowed by the ASME Code. Credit is also taken for the dual relief/safety valves in their ASME Code qualified mode of safety operation. Sizing on this basis is applied to the most severe pressurization transient, which is the main steam isolation valves closure, starting from operation at 105 percent of the reactor warranted steamflow condition.

Reference 2, Figure 4 shows peak, vessel bottom pressures attained when the main steam isolation valve closure transients are terminated by various modes of reactor scram, other than that which would be initiated directly from the isolation event (trip scram). Relief/safety valve capacities for this analysis are 84.0 percent, representative of the 11 relief/safety valves.

The relief/safety valve settings satisfy the Code requirements for relief/ safety valves that the lowest valve set point be at or below the vessel design pressure of 1250 psig. These settings are also sufficiently above the normal operating pressure range to prevent unnecessary cycling caused by minor transients. The results of postulated transients where inherent relief/safety valve actuation is required are given in Section 14.3 of the FSAR.

2. When Operating the RHR System in the Shutdown Cooling Mode

An interlock exists in the logic for the RHR shutdown cooling valves, which are normally closed during power operation, to prevent opening of the valves above a preset pressure setpoint of 135 psig. This setpoint is selected to assure that pressure integrity of the RHR system is maintained. Administrative operating procedures require the operator to close these shutdown cooling valves prior to pressure operation. However, as a backup, the interlock will automatically close these valves when the pressure setpoint is reached. Double indicating lights will be provided in the control room for valve position indication.

Table 3.1-1

REACTOR PROTECTION SYSTEM (RPS) INSTRUMENTATION REQUIREMENTS

When the reactor is subcritical and the reactor water temperature is less than 212°F, only the following sources of scram trip signals need to be operable:

Mode Switch in SHUTDOWN
Manual Scram
IRM High High Flux
Scram Discharge Volume High High Level

Scram Number (a)	Source of Scram Trip Signal	Operable Channels Required Per Trip System (b)	Scram Trip Setting	Source of Scram Signal is Required to be Operable Except as Indicated Below
1	Mode Switch in SHUTDOWN	1	Mode Switch in SHUTDOWN	Automatically bypassed two seconds after the Mode Switch is placed in the SHUTDOWN position.
2	Manual Scram	1	Depression of Manual Scram Button	
3	IRM High High Flux	3	$\leq$120/125 of full scale Tech Spec 2.1.A.1.a	IRMs are automatically bypassed when APRMs are on scale and the Mode Switch is in the Run position.
	Inoperative	3	Not Applicable	IRMs are automatically bypassed when APRMs are on scale and the Mode Switch is in the RUN position.
4	Reactor Vessel Steam Dome Pressure - High	2	$\leq$1054 psig Tech Spec 2.2.A.1	Not required when reactor head is not bolted to the vessel.

Table 3.1-1 (Cont'd)

Scram Number (a)	Source of Scram Trip Signal	Operable Channels Required Per Trip System (b)	Scram Trip Setting	Source of Scram Signal is Required to be Operable Except as Indicated Below
5	High Drywell Pressure	2	$\leq$ 2 psig	Not required to be operable when primary containment integrity is not required. May be bypassed when necessary during purging for containment inerting or deinerting.
6	Reactor Vessel Water Level - Low (Level 3)	2	$\geq$ 8.5 inches	
7	Scram Discharge Volume High High Level			Permissible to bypass (initiates control rod block) in order to reset RPS when the Mode Switch is in the REFUEL or SHUTDOWN position.
	a. Float Switches	2	$\leq$ 71 gallons	
	b. Thermal Level Sensors	2	$\leq$ 71 gallons	
8	APRM Flow Referenced Neutron Flux	2	S $\leq$ 0.66W+54% (Not to exceed 117%) Tech Spec 2.1.A.1.c	
	Fixed High Neutron Flux	2	S $\leq$ 120% Power Tech Spec 2.1.A.1.c	
	Inoperative	2	Not Applicable	An APRM is inoperable if there are less than two LPRM inputs per level or there are less than 11 LPRM inputs to the APRM channel.

Table 3.1-1 (Cont'd)

Scram Number (a)	Source of Scram Trip Signal		Operable Channels Required Per Trip System (b)	Scram Trip Setting	Source of Scram Signal is Required to be Operable Except as Indicated Below
8	APRM	Downscale	2	$\geq$ 3/125 of full scale	The APRM downscale trip is active only when the Mode Switch is in RUN. The APRM downscale trip is automatically bypassed when the IRM instrumentation is operable and not tripped.
		15% Flux	2	$\leq$ 15/125 of full scale Tech Spec 2.1.A.1.b	The APRM 15% Scram is automatically bypassed when the Mode Switch is in the RUN position.
9	Main Steam Line Radiation		2	$\leq$ 3 times normal background at rated thermal power.	Not required if all steam lines are isolated.
10	Main Steam Line Isolation Valve Closure		4	$\leq$ 10% valve closure from full open Tech Spec 2.1.A.5	Automatically bypassed when the Mode Switch is not in the RUN position. The design permits closure of any two lines without a scram being initiated.
11	Turbine Control Valve Fast Closure		2	Within 30 milliseconds of the start of control valve fast closure Tech Spec 2.1.A.4.	Automatically bypassed when turbine steam flow is below 30% of rated as measured by turbine first stage pressure.

Table 4.1-1

Reactor Protection System (RPS) Instrumentation Functional Test, Functional Test Minimum Frequency, and Calibration Minimum Frequency

Scram Number (a)	Source of Scram Trip Signal	Group (b)	Instrument Functional Test Minimum Frequency (c)	Instrument Calibration Minimum Frequency
1	Mode Switch in SHUTDOWN	A	Once/Operating Cycle	Not Applicable
2	Manual Scram	A	Every 3 months	Not Applicable
3	IRM High High Flux	C	Once/Week during refueling and within 24 hours of Startup (e)	Once/Week
	Inoperative	C	Once/week during refueling and within 24 hours of Startup (e)	Once/Week
4	Reactor Vessel Steam Dome Pressure - High	D	Once/Month	Once/operating cycle
5	High Drywell Pressure	A	Once/Month(f)	Every 3 months
6	Reactor Vessel Water Level - Low (Level 3)	D	Once/Month (g)	Once/Operating Cycle
7	Scram Discharge Volume High High Level			
	a. Float Switches	A	Once/Month (f)	(h)
	b. Thermal Level Sensors	B	Once/Month (f)	Once/operating cycle
8	APRM Fixed High Flux	B	Once/Week (e)	Twice/Week
	Inoperable	B	Once/Week (e)	Twice/Week
	Downscale	B	Once/Week (e)	Twice/Week
	Flow Reference	B	Once/Week (f)	Once/Operating Cycle
	15% Flux	C	Within 24 Hours of Startup (e)	Once/Week

Table 4.1-1 (Cont.)

9	Main Steam Line High Radiation	B	Once/Week (e)	Every 3 months (i)
10	Main Steam Line Isolation Valve Closure	A	Once/Month (f)	(h)
11	Turbine Control Valve Fast Closure	A	Once/Month (f) (j)	Once/Operating Cycle (k)
12	Turbine Stop Valve Closure	A	Once/Month (f)	(h)
	RPS Channel Switch	A	Once/Operating Cycle	Not Applicable
	Turbine First Stage Pressure Permissive	A	Every 3 months	Every 6 months
	Reactor Pressure Permissive	A	Every 3 months	Every 6 months
	LPRM Signal	B		Every 1000 Effective Full Power Hours

a. The column entitled "Scram Number" is for convenience so that a one-to-one relationship can be established between items in Table 4.1-1 and items in Table 3.1-1.

b. The definition for each of the four groups is as follows:

Group A. On-off sensors that provide a scram trip signal.
Group B. Analog devices coupled with bi-stable trips that provide a scram trip signal.
Group C. Devices which only serve a useful function during some restricted mode of operation, such as startup or shutdown, or for which the only practical test is one that can be performed at shutdown.
Group D. Analog transmitters and trip units that provide a scram trip function.

c. Functional tests are not required when the systems are not required to be operable or are tripped. However, if functional tests are missed, they shall be performed prior to returning the systems to an operable status.

3.1.A.2. Manual Scram

The manual scram function is active in all modes, thus providing for a manual means of rapidly inserting control rods during all modes of reactor operation.

3. IRM

The bases for the IRM High High Flux Scram Trip Setting are discussed in the bases for Specification 2.1.A.1.a. Each protection trip system has one more IRM channel than is necessary to meet the minimum number required. This allows the bypassing of one IRM channel per protection trip system for maintenance, testing or calibration.

a. High High Flux

The IRM system provides protection against excessive power levels and short reactor periods in the source and intermediate power ranges. The requirement that the IRM's be inserted in the core until the APRM's read 3/125 of full scale or greater assures that there is proper overlap in the neutron monitoring systems and thus, that adequate coverage is provided for all ranges of reactor operation.

A source range monitor (SRM) system is also provided to supply additional neutron level information during start-up but has no scram function (Section 7.5.4 FSAR). Thus, the IRM and APRM systems are required in the Refuel and Start & Hot Standby modes. In the power range, the APRM system provides the required protection (Section 7.5.7 FSAR). Thus, the IRM System is not required when the APRM's are on scale and the Mode Switch is in the RUN position.

b. Inoperative

When an IRM channel becomes unable to perform its normal monitoring function, the condition is recognized and an inopertive trip results. This trip is given the same logic significance as the upscale trip; thus the faulty channel immediately fails safe by contributing to a potential scram condition.

4. Reactor Vessel Steam Dome Pressure - High

High pressure within the nuclear system poses a direct threat of rupture to the nuclear system process barrier. A nuclear system pressure increase while the reactor is operating compresses the steam voids and results in a positive reactivity insertion causing increased core heat generation that could lead to fuel failure and system over-pressurization. A scram counteracts a pressure increase by quickly reducing the core fission heat generation.

The nuclear system high pressure scram setting is chosen slightly above the reactor vessel maximum normal operation pressure to permit normal operation without spurious scrams yet provide a wide margin to the maximum allowable nuclear system pressure. The location of the pressure measurement, as compared to the location of highest nuclear system pressure during transients, was also considered in the selection of the high pressure scram setting. The nuclear system high pressure scram works in conjunction with the pressure relief system in preventing nuclear system pressure from exceeding the maximum allowable pressure. This same nuclear system high pressure scram

3.1.A.4. Reactor Vessel Steam Dome Pressure - High (Continued)

setting also protects the core from exceeding thermal hydraulic limits as a result of pressure increases from some events that occur when the reactor is operating at less than rated power and flow.

5. High Drywell Pressure

Pressure switch instrumentation for the drywell is provided to detect a loss of coolant accident and initiate the core standby cooling equipment. A high drywell pressure scram is provided at the same setting (≤2 psig) as the core standby cooling systems initiation to minimize the energy which must be accommodated during a loss of coolant accident. The instrumentation is a backup to the reactor vessel water level instrumentation.

6. Reactor Vessel Water Level - Low (Level 3)

The bases for the Reactor Vessel Water Level-Low Scram Trip Setting (Level 3) are discussed in the bases for Specification 2.1.A.2.

7. Scram Discharge Volume High High Level

The control rod drive scram system is designed so that all of the water which is discharged from the reactor by a scram can be accommodated in the discharge piping. A part of this piping is an instrument volume which is the low point in the piping. No credit was taken for this volume in the design of the discharge piping as concerns the amount of water which must be accommodated during a scram. During normal operation the discharge volume is empty; however, should the discharge volume fill with water, the water discharged to the piping from the reactor could not be accommodated which would result in a slow scram time or partial or no control rod insertion. To preclude this occurrence, level switches have been provided in the instrument volume which scram the reactor when the volume of water reaches 71 gallons. As indicated above, there is sufficient volume in the piping to accommodate the scram without impairment of the scram times or amount of insertion of the control rods. This function shuts the reactor down while sufficient volume remains to accommodate the discharged water and precludes the situation in which a scram would be required but not able to perform its function adequately.

8. APRM

Three APRM instrument channels are provided for each protection trip system. APRM's A and E operate contacts in one trip logic and APRM's C and E operate contacts in the other trip logic. APRM's B, D and F are arranged similarly in the other protection trip system. Each protection trip system has one more APRM than is necessary to meet the minimum number required per channel. This allows the bypassing of one APRM per protection trip system for maintenance, testing or calibration.

a. Flow Referenced and Fixed High Neutron Flux

The bases for the APRM Flow Referenced and Fixed High Neutron Flux Scram Trip Settings are discussed in the bases for Specification 2.1.A.1.c.

3.1.A.8.b. Inoperative

An APRM is inoperable if there are less than two LPRM inputs per level or there are less that 11 LPRM inputs to the APRM channel.

c. Downscale

The APRM downscale is active only when the Mode Switch is in the RUN position. The APRM downscale trip is automatically bypassed when the IRM instrumentation is operable and not tripped. Because of the APRM downscale limit of $\geq$ 3/125 of full scale when in the Run Mode and high level limit of $\leq$ 15/125 of full scale when in the Start & Hot Standby Mode, the transition between the Start & Hot Standby and Run Modes must be made with the APRM instrumentation indicating between 3/125 and 15/125 of full scale or a control rod scram will occur. In addition, the IRM system must be indicating below the High High Flux setting (120/125 of full scale) or a scram will occur when in the Start & Hot Standby Mode. For normal operating conditions, these limits provide assurance of overlap between the IRM system and APRM system so that there are no "gaps" in the power level indications (i.e., the power level is continuously monitored from beginning of startup to full power and from full power to shutdown). When power is being reduced, if a transfer to the Start & Hot Standby Mode is made and the IRM's have not been fully inserted (a maloperational but not impossible condition) a control rod block immediately occurs so that reactivity insertion by control rod withdrawal cannot occur.

d. 15% Flux

The bases for the APRM 15% Flux Scram Trip Setting is discussed in the bases for Specification 2.1.A.1.b.

9. Main Steam Line High Radiation

High radiation levels in the main steam line tunnel above that due to the normal nitrogen and oxygen radioactivity is an indication of leaking fuel. A scram is initiated whenever such radiation level exceeds a predetermined level above normal background. The purpose of this scram is to reduce the source of such radiation to the extent necessary to prevent excessive turbine contamination. Discharge of excessive amounts of radioactivity to the site environs is prevented by the off-gas post treatment radiation monitors which cause an isolation of the main condenser off-gas line provided the limit specified in the Environmental Technical Specifications is exceeded.

10. Main Steam Line Isolation Valve Closure

The bases for the Main Steam Line Isolation Valve Closure Scram Trip Setting is discussed in the bases for Specification 2.1.A.5.

11. Turbine Control Valve Fast Closure

The bases for the Turbine Control Valve Fast Closure Scram Trip Setting is discussed in the bases for Specification 2.1.A.4.

12. Turbine Stop Valve Closure

The bases for the Turbine Stop Valve Closure Scram Trip Setting is discussed in the bases for Specification 2.1.A.3.

3.1.B. RPS Response Time

Component electrical characteristics are selected so that the system response time, from the opening of a sensor contact up to and including the opening of the trip actuator contacts, is less than 50 milliseconds. A 50 millisecond time delay plus control rod movement and sensor delay time is used in the various transient analyses. For the analog transmitter trip system (ATTS) instrumentation, the sensor consists of a transmitter and the associated trip unit.

C. References

1. FSAR Section 7.2, Reactor Protection System
2. FSAR Section 7.5.4, Source Range Monitor Subsystem
3. FSAR Section 7.5.7, Average Power Range Monitor Subsystem
4. IEEE Standard 279-1971 Criteria for Protection Systems for Nuclear Power Generating Stations

4.1 REACTOR PROTECTION SYSTEM (RPS)

A. Test and Calibration Requirements for the RPS

The minimum functional testing frequency used in this specification is based on a reliability analysis using the concepts developed in Reference 1 and the surveillance frequencies for ATTS equipment approved by the NRC in Reference 2. These concepts were specifically adapted to the one out of two taken twice logic of the reactor protection system. The analysis shows that the sensors are primarily responsible for the reliability of the reactor protection system. This analysis makes use of unsafe failure rate experience at conventional and nuclear power plants in a reliability model for the system. An unsafe failure is defined as one which negates channel operability and which, due to its nature, is revealed only when the channel is functionally tested or attempts to respond to a real signal. Failures such as blown fuses, ruptured bourdon tubes, faulted amplifiers, faulted cables, etc., which result in upscale or downscale readings on the reactor instrumentation are safe and will be easily recognized by the operators during operation because they are revealed by an alarm or a scram.

The channels listed in Table 4.1-1 are divided into four groups for functional testing. These are:

- Group A. On-Off Sensors that provide a scram trip function.
- Group B. Analog devices coupled with bi-stable trips that provide a scram function.
- Group C. Devices which only serve a useful function during some restricted mode of operation, such as startup or shutdown, or for which the only practical test is one that can be performed at shutdown.
- Group D. Analog transmitters and trip units that provide a scram trip function.

The sensors that make up Group A are specifically selected from among the whole family of industrial on-off sensors that have earned an excellent reputation for reliable operation. During design, a goal of 0.99999 probability of success at the 50% confidence level was adopted to assure that a balanced and adequate design is achieved. The probability of success is primarily a function of the sensor failure rate and the test interval. A three-month test interval was planned for Group A sensors. This is in keeping with good operating practices, and satisfies the design goal for the logic configuration utilized in the Reactor Protection System.

To satisfy the long-term objective of maintaining an adequate level of safety throughout the plant lifetime, a minimum goal of 0.9999 at the 95% confidence level is proposed. With the one out of two taken twice logic, this requires that each sensor have an availability of 0.993 at the 95% confidence level. This level of availability may be maintained by adjusting the test interval as a function of the observed failure history (Ref. 1). To facilitate the implementation of this technique, Figure 4.1-1 is provided to indicate an appropriate trend in test interval. The procedure is as follows:

1. Like sensors are pooled into one group for the purpose of data acquisition.
2. The factor M is the exposure hours and is equal to the number of sensors

4.1.A.2. Test and Calibration Requirements for the RPS (Continued)

in a group, n, times the elapsed time T, therefore M = n T.

3. The accumulated number of unsafe failures is plotted as an ordinate against M as an abscissa on Figure 4.1-1.

4. A test interval of one month will be used initially until a trend is established.

5. After a trend is established, the appropriate test interval to satisfy the goal will be the test interval to the left of the plotted points.

Group B devices utilize an analog sensor followed by an amplifier and a bistable trip circuit. The sensor and amplifier are active components and a failure is almost always accompanied by an alarm and an indication of the source of trouble. In the event of failure, repair or substitution can start immediately. An "as-is" failure is one that sticks mid-scale and is not capable of going either up or down in response to an out-of-limits in-put. This type of failure for analog devices is a rare occurrence and is detectable by an operator who observes that one signal does not track the other three. For purposes of analysis, it is assumed that this failure will be detected within two hours.

The bi-stable trip circuit which is a part of the Group B devices can sustain unsafe failures which are revealed only on test. Therefore, it is necessary to test them periodically.

A study was conducted of the instrumentation channels included in the Group B devices to calculate their "unsafe" failure rates. The analog devices (sensors and amplifiers) are predicted to have an unsafe failure rate of less than 20 X 10^{-6} failures/hour. The bi-stable trip circuits are predicted to have unsafe failure rate of less than 2 X 10^{-6} failures/hour. Considering the two hour monitoring interval for the analog devices as assumed above, and a weekly test interval for the bi-stable trip circuits, the design reliability goal of 0.99999 is attained with ample margin.

The bi-stable devices are monitored during plant operation to record their failure history and establish a test interval using the curve of Figure 4.1-1. There are numerous identical bi-stable devices used throughout the plant's instrumentation system. Therefore, significant data on the failure rates for the bi-stable devices should be accumulated rapidly.

The frequency of calibration of the APRM Flow Referencing Network has been established as once per operating cycle. There are several instruments which must be calibrated and it will take several hours to perform the calibration of the entire network. While the calibration is being performed, a zero flow signal will be sent to half of the APRM's resulting in a half scram and rod block condition. Thus, if the calibration were performed during operation, flux shaping would not be possible. Based on experience at other generating stations, drift of instruments, such as those in the Flow Referencing Network, is not significant and therefore, to avoid spurious scrams, a calibration frequency of once per operating cycle is established.

4.1.A. Test and Calibration Requirements for the RPS (Continued)

Group C devices are active only during a given portion of the operational cycle. For example, the IRM is active during startup and inactive during full-power operation. Thus, the only test that is meaningful is the one performed just prior to shutdown or startup; i.e., the tests that are performed just prior to use of the instrument.

Calibration frequency of the instrument channel is divided into two categories: They are as follows:

i. Passive type indicating devices that can be compared with like units on a continuous reference.

ii. Vacuum tube or semiconductor devices and detectors that drift or lose sensitivity.

Experience with passive type instruments in generating stations and substations indicates that the specified calibrations are adequate. For those devices which employ amplifiers, etc., drift specifications call for drift to be less than 0.4%/month; i.e., in the period of a month a drift of .4% could occur and still provide for adequate margin. For the APRM system, drift of electronic apparatus is not the only consideration in determining a calibration frequency. Change in power distribution and loss of chamber sensitivity dictate a calibration every seven (7) days. Calibration on this frequency assures plant operation at or below thermal limits.

The sensitivity of LPRM detectors decreases with exposure to neutron flux at a slow and approximately constant rate. This is compensated for in the APRM system by calibrating twice a week using heat balance data and by calibrating individual LPRM's every 1000 effective full power hours using TIP traverse data.

Group D devices consist of analog transmitters, master trip units, slave trip units, and other accessories. The general description of the ATTS devices is provided in Reference 3. As evidenced by NEDO-21617-A, the NRC has approved the following surveillance frequencies for ATTS equipment:

1. Once per shift for channel check
2. Once per month for channel functional test
3. Once per operating cycle for channel calibration

B. Maximum Fraction of Limiting Power Density (MFLPD)

Since changes due to burnup are slow, and only a few control rods are moved daily, a daily check of the MFLPD is adequate. The determination of the MFLPD would establish whether or not adjustment of the APRM reading is required.

4.1.C. References

1. I. M. Jacobs, "Reliability of Engineered Safety Features as a Function of Testing Frequency," Nuclear Safety, Volume 9, No. 4, July-August, 1968, pp 303-312.

2. NEDO-21617-A, "Analog Transmitter/Trip Unit System for Engineered Safeguard Sensor Trip Inputs."

3. NEDE-22154-1, "Analog Trip System for Engineered Safeguard Sensor Trip Inputs - Edwin I. Hatch Nuclear Plant Units 1 and 2."

3.2 PROTECTIVE INSTRUMENTATION

Applicability

The Limiting Conditions for Operation apply to the plant instrumentation which performs a protective function.

Objective

The objective of the Limiting Conditions for Operation is to assure the operability of protective instrumentation.

Specifications

The Limiting Conditions for Operation of the protective instrumentation affecting each of the following protective actions shall be as indicated in the corresponding LCO table.

4.2 PROTECTIVE INSTRUMENTATION

Applicability

The Surveillance Requirements apply to the instrumentation which performs a protective function.

Objective

The objective of the Surveillance Requirements is to specify the type and frequency of surveillance to be applied to protective instrumentation.

Specifications

The check, functional test, and calibration minimum frequency for protective instrumentation affecting each of the following protective actions shall be as indicated in the corresponding SR table.

	Protective Action	LCO Table	SR Table
A.	Initiates Reactor Vessel and Containment Isolation	3.2-1	4.2-1
B.	Initiates or Controls HPCI	3.2-2	4.2-2
C.	Initiates or Controls RCIC	3.2-3	4.2-3
D.	Initiates or Controls ADS	3.2-4	4.2-4
E.	Initiates or Controls the LPCI Mode of RHR	3.2-5	4.2-5
F.	Initiates or Controls Core Spray	3.2-6	4.2-6
G.	Initiates Control Rod Blocks	3.2-7	4.2-7
H.	Limits Radioactivity Release	3.2-8	4.2-8
I.	Initiates Recirculation Pump Trip	3.2-9	4.2-9
J.	Monitors Leakage Into the Drywell	3.2-10	4.2-10
K.	Provides Surveillance Information	3.2-11	4.2-11
L.	Initiates Disconnection of Offsite Power Sources	3.2-12	4.2-12
M.	Initiates Energization by Onsite Power Sources	3.2-13	4.2-13
N.	Arms the Low Low Set S/RV System	3.2-14	4.2-14

Table 3.2-1

INSTRUMENTATION WHICH INITIATES REACTOR VESSEL AND PRIMARY CONTAINMENT ISOLATION

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Action to be taken if number of channels is not met for both trip systems (c)	Remarks (d)
1	Reactor Vessel Water Level	Low (Level 3) Narrow Range	2	≥ 8.5 inches	Initiate an orderly shutdown and achieve the Cold Shutdown Condition within 24 hours or isolate the shutdown cooling system.	Initiates Group 2 & 6 isolation.
		Low Low (Level 2)	2	≥-55 inches	Initiate an orderly shutdown and achieve the Cold Shutdown Condition within 24 hours.	Starts the SGTS, initiates Group 5 isolation, and initiates secondary containment isolation.
		Low Low Low (Level 1)	2	≥-121.5 inches	Initiate an orderly shutdown and achieve the Cold Shutdown Condition within 24 hours.	Initiates Group 1 isolation.
2	Reactor Pressure (Shutdown Cooling Mode)	High	1	≤135 psig	Isolate shutdown cooling.	Isolates the shutdown cooling suction valves of the RHR system.
3	Drywell Pressure	High	2	≤ 2 psig	Initiate an orderly shutdown and achieve the Cold Shutdown Condition within 24 hours	Starts the standby gas treatment system, initiates Group 2 isolation and secondary containment isolation.
4	Main Steam Line Radiation	High	2	≤ 3 times normal full-power background	Initiate an orderly load reduction and close MSIVs within 8 hours	Initiates Group 1 isolation.

Table 3.2-2

INSTRUMENTATION WHICH INITIATES OR CONTROLS HPCI

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low Low (Level 2)	2	$\geq$ -55 inches	Initiates HPCI; Also initiates RCIC.
2.	Drywell Pressure	High	2	$\leq$ 2 psig	Initiates HPCI; Also initiates LPCI and Core Spray and provides a permissive signal to ADS.
3.	HPCI Turbine Overspeed	Mechanical	1	$\leq$ 5000 rpm	Trips HPCI turbine
4.	HPCI Turbine Exhaust Pressure	High	1	$\leq$ 150 psig	Trips HPCI turbine
5.	HPCI Pump Suction Pressure	Low	1	$\leq$ 15 inches Hg vacuum	Trips HPCI turbine
6.	Reactor Vessel Water level	High (Level 8)	2	$\leq$ +56.5 inches	Trips HPCI turbine
7.	HPCI System Flow (Flow Switch)	High	1	> 800 gpm	Closes HPCI minimum flow bypass line to suppression chamber.
		Low	1	$\leq$ 500 gpm	Opens HPCI minimum flow bypass line if pressure permissive is present.
8.	HPCI Equipment Room	High	1	$\leq$ 175°F	Closes isolation valves in HPCI system, trips HPCI turbine.

Table 3.2-3

INSTRUMENTATION WHICH INITIATES OR CONTROLS RCIC

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low Low (Level 2)	2	≥-55 inches	Initiates RCIC; also initiates HPCI.
2.	RCIC Turbine Overspeed	Electrical	1	≤110% rated	Trips RCIC turbine.
		Mechanical	1	≤125% rated	Trips RCIC turbine.
3.	RCIC Turbine Exhaust Pressure	High	1	≤+25 psig	Trips RCIC turbine.
4.	RCIC Pump Suction Pressure	Low	1	≤ 15 inches Hg Vacuum	Trips RCIC turbine.
5.	Reactor Vessel Water Level	High (Level 8)	2	≤+56.5 inches	Trips RCIC; automatically resets when water drops below level 8, system automatically restarts at level 2.
6.	RCIC System Flow (Flow Switch)	High	1	>80 gpm	Closes RCIC minimum flow bypass line to suppression chamber.
		Low	1	≤40 gpm	Opens RCIC minimum flow bypass line if pressure permissive is present.
7.	RCIC Equipment Room	High	1	≤175°F	Closes isolation valves in RCIC system, trips RCIC turbine.

Table 3.2-4

INSTRUMENTATION WHICH INITIATES OR CONTROLS ADS

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low (Level 3)	1	$\geq$8.5 inches	Confirms low level, ADS permissive
	Reactor Vessel Water Level	Low Low Low (Level 1)	2	$\geq$-121.5 inches	Permissive signal to ADS timer
2.	Drywell Pressure	High	2	$\leq$2 psig	Permissive signal to ADS timer
3.	RHR Pump Discharge Pressure	High	2	$\geq$100 psig	Permissive signal to ADS timer
4.	CS Pump Discharge Pressure	High	2	$\geq$100 psig	Permissive signal to ADS timer
5.	Auto Depressurization Timer		1	120 ± 12 seconds	With Level 3 and Level 1 and high drywell pressure and CS or RHR pump at pressure, timing sequence begins. If the ADS timer is not reset it will initiate ADS.
6.	Automatic Blowdown Control Power Failure Monitor		1	Not applicable	Monitors availability of power to logic system

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.2-4 and items in Table 4.2-4.

b. Whenever any CCCS subsystem is required to be operable by Section 3.5, there shall be two operable trip systems. If the required number of operable channels cannot be met for one of the trip systems, that system shall be repaired or the reactor shall be placed in the Cold Shutdown Condition within 24 hours after this trip systems is made or found to be inoperable.

Table 3.2-5

INSTRUMENTATION WHICH INITIATES OR CONTROLS THE LPCI MODE OF RHR

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low Low Low (Level 1)	2	≥ -121.5 inches	Initiates LPCI mode of RHR
2.	Drywell Pressure	High	2	≤ 2 psig	Initiates LPCI mode of RHR
3.	Reactor Vessel Steam Dome Pressure	High (Shutdown Cooling Mode)	1	≤ 135 psig	With primary containment isolation signal, closes RHR (LPCI) inboard motor operated injection valves
		Low	2	≥ 325 psig	Permissive to close Recirculation Discharge Valve and Bypass Valve
		Low	2	≥ 422 psig*	Permissive to open LPCI injection valves
4.	Reactor Water Level (Shroud Level Indicator)		1	≥-203.5 inches	Acts as permissive to divert some LPCI flow to containment spray
5.	LPCI Cross Connect Valve Open Annunciator	N/A	1	Valve not closed	Initiates annunciator when valve is not closed

*This trip function shall be ≤500 psig.

Notes for Table 3.2-5

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.2-5 and item in Table 4.2-5.

b. Whenever any CCCS subsystem is required to be operable by Section 3.5, there shall be two operable trip systems. If the required number of operable channels cannot be met for one of the trip systems, that system shall be repaired or the reactor shall be placed in the Cold Shutdown Condition within 24 hours after this trip systems is made or found to be inoperable.

Table 3.2-6

INSTRUMENTATION WHICH INITIATES OR CONTROLS CORE SPRAY

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low Low Low (Level 1)	2	$\geq$-121.5 inches	Initiates CS.
2.	Drywell Pressure	High	2	$\leq$ 2 psig	Initiates CS.
3.	Reactor Vessel Steam Dome Pressure	Low	2	$\geq$ 422 psig*	Permissive to open CS injection valves.
4.	Core Spray Sparger Differential Pressure		1	To be determined during startup testing	Monitors integrity of CS piping inside vessel and core shroud.
5.	CS Pump Discharge Flow (Flow Switch)	Low	1	$\geq$ 475 gpm	Minimum flow bypass line is closed when low flow signal is not present.
6.	Core Spray Pump Discharge Pressure Interlock		2	$\geq$100 psig	Defers ADS actuation until LPCI or CS pump is confirmed to be running
7.	Core Spray Logic Power Failure Monitor		1	Not Applicable	Monitors availability of power to logic system.

*This trip function shall be $\leq$500 psig.

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.2-6 and items in Table 4.2-6.

b. Whenever any CCCS subsystem is required to be operable by Section 3.5, there shall be two operable trip systems. If the required number of operable channels cannot be met for one of the trip systems, that system shall be repaired or the reactor shall be placed in the Cold Shutdown Condition within 24 hours after this trip system is made or found to be inoperable.

Table 3.2-9

INSTRUMENTATION WHICH INITIATES RECIRCULATION PUMP TRIP

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System	Trip Setting	Remarks
1.	Reactor Vessel Water Level (ATWS RPT)[c]	Low	$1^{(b)}$	$\geq$ -38 inches	Power must be reduced and the mode switch placed in a mode other than the RUN Mode.
2.	Reactor Pressure (ATWS RPT)	High	$1^{(b)}$	$\leq$1120 psig	Power must be reduced and the mode switch placed in a mode other than the RUN Mode.
3.	EOC - RPT[d]	1. Turbine Stop Valve Closure 2. Turbine Control Valve Fast Closure	$2^{(e)(f)}$	1. Stop Valve $\leq$90% Open 2. Control Valve Hydraulic Press Trip Point	Trips recirculation pumps on turbine control valve fast closure or stop valve closure when reactor is > 30%.[e]

(a) The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.2-9 and items in Table 4.2-9.

(b) Whenever the reactor is in the RUN Mode, there shall be one operable trip system for each parameter for each operating recirculation pump, except that one trip system may remain inoperable for up to 14 days. If this cannot be met, the indicated action shall be taken.

(c) Anticipated Transients Without Scram - Recirculation Pump Trip

(d) End of Cycle - Recirculation Pump Trip

(e) Either of these two EOC - RPT systems can trip both recirculation pumps. Each EOC - RPT system will trip if 2-out-of-2 fast closure signals _or_ 2-out-of-2 stop valve signals are received.

(f) The requirement for these channels applies from EOC-2000 MWD/t to EOC. The RPT system may be placed in an inoperable status for up to 2 hours to provide the required monthly surveillance. If one EOC-RPT system is inoperable for longer than 72 hours or if both EOC-RPT systems are simultaneously inoperable, an orderly power reduction will be immediately initiated and reactor power will be <30% within the next 6 hours.

Table 3.2-11

INSTRUMENTATION WHICH PROVIDES SURVEILLANCE INFORMATION

Ref. No. (a)	Instrument (b)	Required Operable Instrument Channels	Type and Range	Action	Remarks
1	Reactor Vessel Water Level	1	Recorder	(c)	(d)
		2	Indicator 0 to 60"	(c)	(d)
2	Shroud Water Level	1	Recorder	(c)	(d)
		1	Indicator -317" to -17"	(c)	(d)
3	Reactor Pressure	1	Recorder 0 to 1500 psig	(c)	(d)
		2	Indicator 0 to 1200 psig	(c)	(d)
4	Drywell Pressure	2	Recorder -5 to +80 psig	(c)	(d)
5	Drywell Temperature	2	Recorder 0 to 500°F	(c)	(d)
6	Suppression Chamber Air Temperature	2	Recorder 0 to 500°F	(c)	(d)
7	Suppression Chamber Water Temperature	2	Recorder 0 to 250°F	(c)	(d)
8	Suppression Chamber Water Level	2	Indicator 0 to 300"	(c)	(d)
		2	Recorder 0 to 30"	(c)(e)	(d)
9	Suppression Chamber Pressure	2	Recorder -5 to +80 psig	(c)	(d)
10	Rod Position Information System (RPIS)	1	28 Volt Indicating Lights	(c)	(d)
11	Hydrogen and Oxygen Analyzer	1	Recorder 0 to 52	(c)	(d)
12	Post LOCA Radiation Monitoring System	1	Recorder	(c)	(d)
			Indicator 1 to 10^6 R/hr	(c)	(d)
13	a) Safety/Relief Valve Position Primary Indicator	1/SRV	Indicating Light at 85 psig	(f)	
	b) Safety/Relief Valve Position Secondary Indicator	1	Recorder 0 to 600°F	(f)	

Table 3.2-14

INSTRUMENTATION WHICH ARMS LOW LOW SET S/RV SYSTEM

Ref No.[(a)]	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System	Trip Setting	Remarks
1.	Reactor Vessel Steam Dome Pressure	High	2[(b)]	$\leq$ 1054 psig	
2.	Relief/Safety Valve Tailpipe Pressure	High	2/valve	85, +15, -5 psig	The limiting condition of operation of these switches is provided in Specification 3.6.H.1

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in table 3.2-14 and items in table 4.2-14.

b. With the requirements for the minimum number of OPERABLE channels not satisfied for one trip system, place the inoperable channel in the tripped condition or declare the associated system inoperable within one hour. With the requirements for the minimum number of OPERABLE channels not satisfied for both trip systems, declare the associated system inoperable within one hour.

Table 4.2-1

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation Which Initiates Reactor Vessel and Primary Containment Isolation

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Levels 1, 2, and 3)	Once/shift	Once/month	Once/operating cycle
2	Reactor Pressure (Shutdown Cooling Mode)	None	(d)	Every 3 months
3	Drywell Pressure	None	(d)	Every 3 months
4	Main Steam Line Radiation	None	Once/week (e)	Every 3 months (f)
5	Main Steam Line Pressure	None	(d)	Every 3 months
6	Main Steam Line Flow	None	(d)	Every 3 months
7	Main Steam Line Tunnel Temperature	None	Once/operating cycle	Once/operating cycle
8	Reactor Water Cleanup System Differential Flow	None	(d)	Every 3 months
9	Reactor Water Cleanup Equipment Room Temperature	None	(d)	Every 3 months

Table 4.2-2

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation Which Initiates or Controls HPCI

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 2)	Once/shift	Once/month	Once/operating cycle
2	Drywell Pressure	None	(d)	Every 3 months
3	HPCI Turbine Overspeed	None	N/A	Once/operating cycle
4	HPCI Turbine Exhaust Pressure	None	(d)	Every 3 months
5	HPCI Pump Suction Pressure	None	(d)	Every 3 months
6	Reactor Vessel Water Level (Level 8)	Once/shift	Once/month	Once/operating cycle
7	HPCI System Flow (Flow Switch)	None	(d)	Every 3 months
8	HPCI Equipment Room Temperature	None	(d)	Every 3 months
9	deleted			
10	HPCI Steam Line Pressure	None	(d)	Every 3 months

Table 4.2-3

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation Which Initiates or Controls RCIC

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 2)	Once/shift	Once/month	Once/operating cycle
2	RCIC Turbine Overspeed			
	Electrical/	None	N/A	Once/operating cycle
	Mechanical	None	N/A	Once/operating cycle
3	RCIC Turbine Exhaust Pressure	None	(d)	Every 3 months
4	RCIC Pump Suction Pressure	None	(d)	Every 3 months
5	Reactor Vessel Water Level (Level 8)	Once/shift	Once/month	Once/operating cycle
6	RCIC System Flow (Flow Switch)	None	(d)	Every 3 months
7	RCIC Equipment Room Temperature	None	(d)	Every 3 months
8	deleted			
9	RCIC Steam Line Pressure	None	(d)	Every 3 months

Table 4.2-4

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation Which Initiates or Controls ADS

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 3)	Once/shift	Once/month	Once/operating cycle
	Reactor Vessel Water Level (Level 1)	Once/shift	Once/month	Once/operating cycle
2	Drywell Pressure	None	(d)	Every 3 months
3	RHR Pump Discharge Pressure	None	(d)	Every 3 months
4	CS Pump Discharge Pressure	None	(d)	Every 3 months
5	Auto Depressurization Timer	None	N/A	Once/operating cycle
6	Automatic Blowdown Control Power Failure Monitor	None	Once/operating cycle	None

Notes for Table 4.2-4

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 4.2-4 and items in Table 3.2-4.

Notes for Table 4.2-4 (Cont'd)

b. Instrument functional tests are not required when the instruments are not required to be operable or are tripped. However, if functional tests are missed, they shall be performed prior to returning the instrument to an operable status.

c. Calibrations are not required when the instruments are not required to be operable. However, if calibrations are missed, they shall be performed prior to returning the instrument to an operable status.

d. Initially once per month or according to Figure 4.1-1 with an interval of not less than one month nor more than three months. The compilation of instrument failure rate data may include data obtained from other BWR's for which the same design instrument operates in an environment similar to that of HNP-1. The failure rate data must be reviewed and approved by the AEC prior to any change in the once-a-month frequency

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Logic system functional tests and simulated automatic actuation shall be performed once each operating cycle for the following:

1. ADS Subsystem

The logic system functional tests shall include a calibration of time relays and timers necessary for proper functioning of the trip systems.

Table 4.2-5

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation Which Initiates or Controls the LPCI Mode of RHR

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 1)	Once/shift	Once/month	Once/operating cycle
2	Drywell Pressure	None	(d)	Every 3 months
3	Reactor Vessel Steam Dome Pressure	Once/shift	Once/month	Once/operating cycle
4	Reactor Water Level (Shroud Level Indicator)	Once/day	(d)	Every 3 months
5	LPCI Cross Connect Valve Open Annunciator	None	Once/Operating cycle	None
6	RHR (LPCI) Pump Discharge Pressure Interlock	None	(d)	Every 3 months
7	RHR (LPCI) Pump Flow (Flow Switch)	None	(d)	Every 3 months
8	RHR (LPCI) Pump Start Timers	None	N/A	Once/operating cycle
9	Valve Selection Timers	None	N/A	Once/operating cycle
10	RHR Relay Logic Power Failure Monitor	None	Once/operating cycle	None

Notes for Table 4.2-5 (Cont'd)

The logic functional tests shall include a calibration of time relays and timers necessary for proper functioning of the trip systems.

Table 4.2-6

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation Which Initiates or Controls Core Spray

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 1)	Once/shift	Once/month	Once/operating cycle
2	Drywell Pressure	None	(d)	Every 3 months
3	Reactor Vessel Steam Dome Pressure	Once/shift	Once/month	Once/operating cycle
4	Core Spray Sparger Differential Pressure	Once/day	N/A	Once/operating cycle
5	CS Pump Discharge Flow (Flow Switch)	None	(d)	Every 3 months
6	Core Spray Pump Discharge Pressure Interlock	None	(d)	Every 3 months
7	Core Spray Logic Power Failure Monitor	None	Once/operating cycle	None

Notes for Table 4.2-6

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 4.2-6 and items in Table 3.2-6.

Table 4.2-9

CHECK AND CALIBRATION MINIMUM FREQUENCY FOR INSTRUMENTATION
WHICH INITIATES RECIRCULATION PUMP TRIP

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency	Instrument Calibration Minimum Frequency
1	Reactor Vessel Water Level (ATWS RPT) (b)	Once/day	Once/operating cycle	Once/operating cycle
2	Reactor Pressure (ATWS RPT)	None	Once/operating cycle	Once/operating cycle
3	EOC - RPT Trip			
	a) Initiating Logic	None	Once/month	None
	b) Breakers	None	Once/operating cycle	None
	c) Response Time RPT logics + Breakers	None	None	Once/operating cycle

Notes for Table 4.2-9

(a) The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.2-9 and items in Table 4.2-9.

(b) An ATWS recirculation pump trip logic system functional test shall be performed once per operating cycle.

Table 4.2-14

CHECK, FUNCTIONAL TEST, AND CALIBRATION MINIMUM FREQUENCY FOR INSTRUMENTATION
WHICH ARMS THE LOW LOW SET S/RV SYSTEM

Ref No.[a]	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency[b]	Instrument Calibration Minimum Frequency[c]
1	Reactor Vessel Steam Dome Pressure	Once/shift	Once/month	Once/operating cycle
2	Relief/Safety Valve Tailpipe Pressure	N/A	Once/month(d)	Once/operating cycle(e)

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in table 4.2-14 and items in table 3.2-14.

b. Instrument functional tests are not required when the instruments are not required to be operable or are tripped. However, if functional tests are missed, they shall be performed prior to returning the instrument to an operable status.

c. Calibrations are not required when the instruments are not required to be operable. However, if calibrations are missed, they shall be performed prior to returning the instrument to an operable status.

d. See section 4.6.H.1.e.1 for exceptions to this pressure switch functional test frequency.

e. See section 4.6.H.1.e.2.

3.2 PROTECTIVE INSTRUMENTATION

In addition to the Reactor Protection System (RPS) instrumentation which initiates a reactor scram, protective instrumentation has been provided which initiates action to mitigate the consequences of accidents which are beyond the operators ability to control, or terminates operator errors before they result in serious consequences. This set of Specifications provides the limiting conditions for operation of the instrumentation:
(a) which initiates reactor vessel and primary containment isolation,
(b) which initiates or controls the core and containment cooling systems,
(c) which initiates control rod blocks, (d) which initiates protective action,
(e) which monitors leakage into the drywell and (f) which provides surveillance information. The objectives of these specifications are (i) to assure the effectiveness of the protective instrumentation when required by preserving its capability to tolerate a single failure of any component of such systems even during periods when portions of such systems are out of service for maintenance, and (ii) to prescribe the trip settings required to assure adequate performance. When necessary, one channel may be made inoperable for brief intervals to conduct required functional tests and calibrations.

A. Instrumentation Which Initiates Reactor Vessel and Primary Containment Isolation (Table 3.2-1)

Isolation valves are installed in those lines which penetrate the primary containment and must be isolated during a loss of coolant accident so that the radiation dose limits are not exceeded during an accident condition. Actuation of these valves is initiated by protective instrumentation shown in Table 3.2-1 which senses the conditions for which isolation is required. Such instrumentation must be available whenever primary containment integrity is required. The objective is to isolate the primary containment so that the guidelines of 10 CFR 100 are not exceeded during an accident. The events when isolation is required are discussed in Appendix G of the FSAR. The instrumentation which initiates primary system isolation is connected in a dual bus arrangement.

1. Reactor Vessel Water Level

a. Reactor Vessel Water Level Low (Level 3) (Narrow Range)

The reactor water level instrumentation is set to trip when reactor water level is approximately 14 feet above the top of the active fuel. This level is referred to as Level 3 in the Technical Specifications and corresponds to a reading of 8.5 inches on the Narrow Range Scale. This trip initiates Group 2 and 6 isolation but does not trip the recirculation pumps.

b. Reactor Vessel Water Level Low Low (Level 2)

The reactor water level instrumentation is set to trip when reactor water level is approximately 8 feet above the top of the active fuel. This level is referred to as Level 2 in the Technical Specifications and corresponds to a reading of -55 inches.
This trip initiates Group 5 isolation, starts the standby gas treatment system, and initiates secondary containment isolation.

3.2.A.1.c. Reactor Vessel Water Level Low Low Low (Level 1)

The reactor water level instrumentation is set to trip when the reactor water level is approximately 43 inches above the top of the active fuel. This level is referred to as Level 1 in the Technical Specifications and corresponds to a reading of -121.5 inches. This trip initiates Group 1 isolation.

3.2.A.7 Main Steam Line Tunnel Temperature High (Continued)

with the resultant small release of radioactivity, gives isolation before the guidelines of 10 CFR 100 are exceeded.

8. Reactor Water Cleanup System Differential Flow High

Gross leakage (pipe break) from the reactor water cleanup system is detected by measuring the difference of flow entering and leaving the system. The set point is low enough to ensure prompt isolation of the cleanup system in the event of such a break but, not so low that spurious isolation can occur due to normal system flow fluctuations and instrument noise. Time delay relays are used to prevent the isolation signal which might be generated from the initial flow surge when the cleanup system is started or when operational system adjustments are made which produce short term transients.

9. Reactor Water Cleanup Equipment Room Temperature High and

10. Reactor Water Cleanup Equipment Room Differential Temperature High

Leakage in the high temperature process flow of the reactor water cleanup system external to the primary containment will be detected by temperature sensing elements. Temperature sensors are located in the inlet and outlet ventilation ducts to measure the temperature difference. Local ambient temperature sensors are located in the compartment containing equipment and piping for this system. An alarm in the main control room will be set to annunciate a temperature rise corresponding to a leakage within the identified limit. In addition to annunciation, a high cleanup room temperature will actuate automatic isolation of the cleanup system.

11. Condenser Vacuum Low

The Bases for Condenser Vacuum Low are discussed in The Bases for Specification 2.1.A.7.

B. Instrumentation Which Initiates or Controls HPCI (Table 3.2-2)

1. Reactor Vessel Water Level Low Low (Level 2)

The reactor vessel water level instrumentation setpoint which initiates HPCI is ≥ -55 inches. This level is approximately 8 feet above the top of the active fuel and in the Technical Specifications is referred to as Level 2. The reactor vessel low water level setting for HPCI system initiation is selected high enough above the active fuel to start the HPCI system in time both to prevent excessive fuel clad temperatures and to prevent more than a small fraction of the core from reaching the temperature at which gross fuel failure occurs. The water level setting is far enough below normal levels that spurious HPCI system startups are avoided.

2. Drywell Pressure High

The drywell pressure instrumentation setpoint with initiates HPCI is ≤ 2 psig. High drywell pressure is indicative of a failure of the nuclear system process barrier. This pressure is selected to be as low as possible without inducing spurious HPCI system startups. This instrumentation serves as a backup to the water level instrumentation described above.

3.2.B.3 HPCI Turbine Overspeed

The HPCI turbine is automatically shut down by tripping the HPCI turbine stop valve closed when the 5000 rpm setpoint on the mechanical governor is reached. A turbine overspeed trip is required to protect the physical integrity of the turbine.

4. HPCI Turbine Exhaust Pressure High

When HPCI turbine exhaust pressure reaches the setpoint ($\leq$ 150 psig) the HPCI turbine is automatically shut down by tripping the HPCI stop valve closed. HPCI turbine exhaust high pressure is indicative of a condition which threatens the physical integrity of the exhaust line.

5. HPCI Pump Suction Pressure Low

A pressure switch is used to detect HPCI system pump suction pressure and is set to trip the HPCI turbine at $\leq$ 15 inches of mercury vacuum. This setpoint is chosen to prevent pump damage by cavitation.

6. Reactor Vessel Water Level High (Level 8)

A reactor water level of +56.5 inches is indicative that the HPCI system has performed satisfactorily in providing makeup water to the reactor vessel. The reactor vessel high water level setting which trips the HPCI turbine is near the top of the steam separators and is sufficient to prevent gross moisture carryover to the HPCI turbine. Two analog differential pressure transmitters trip to initiate a HPCI turbine shutdown.

7. HPCI System Flow

To prevent damage by overheating at reduced HPCI system pump flow, a pump discharge minimum flow bypass is provided. The bypass is controlled by an automatic, D. C. motor-operated valve. A high flow signal from a flow meter downstream of the pump on the main HPCI line will cause the bypass valve to close. Two signals are required to open the valve: A HPCI pump discharge pressure switch high pressure signal must be received to act as a permissive to open the bypass valve in the presence of a low flow signal from the flow switch.

NOTE:

Because the steam supply line to the HPCI turbine is part of the nuclear system process barrier, the following conditions (8-14) automatically isolate this line, causing shutdown of the HPCI system turbine.

8. HPCI Equipment Room Temperature High

High ambient temperature in the HPCI equipment room near the emergency area cooler could indicate a break in the HPCI system turbine steam line. The automatic closure of the HPCI steam line valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. The high

3.2.B.14 Suppression Chamber Area Differential Air Temperature High

As for the HPCI equipment room differential temperature, and for the same reason, a differential air temperature greater than the trip setting of ≤ 42°F between the inlet and outlet ducts which ventilate the suppression chamber area will initiate a timer to isolate the HPCI turbine steam line.

15. Condensate Storage Tank Level Low

The CST is the preferred source of suction for HPCI. In order to provide an adequate water supply, an indication of low level in the CST automatically switches the suction to the suppression chamber. A trip setting of 0 inches corresponds to 10,000 gallons of water remaining in the tank.

16. Suppression Chamber Water Level High

A high water level in the suppression chamber automatically switches HPCI suction to the suppression chamber from the CST.

17. HPCI Logic Power Failure Monitor

The HPCI Logic Power Failure Monitor monitors the availability of power to the logic system. In the event of loss of availability of power to the logic system, an alarm is annunciated in the control room.

C. Instrumentation Which Initiates or Controls RCIC (Table 3.2-3)

1. Reactor Vessel Water Level Low Low (Level 2)

The reactor water level instrumentation setpoint which initiates RCIC is ≥ -55 inches. This level is approximately 8 feet above the top of the active fuel and is referred to as Level 2. This setpoint insures that RCIC is started in time to preclude conditions which lead to inadequate core cooling.

2. RCIC Turbine Overspeed

The RCIC turbine is automatically shutdown by tripping the RCIC turbine stop valve closed when the 125% speed at rated flow setpoint on the mechanical governor is reached. Turbine overspeed is indicative of a condition which threatens the physical integrity of the system. An electrical tachometer trip setpoint of 110% also will trip the RCIC turbine stop valve closed.

3. RCIC Turbine Exhaust Pressure High

When RCIC turbine exhaust pressure reaches the setpoint (≤ 25 psig), the RCIC turbine is automatically shut down by tripping the RCIC turbine stop valve closed. RCIC turbine exhaust high pressure is indicative of a condition which threatens the physical integrity of the exhaust line.

4. RCIC Pump Suction Pressure Low

One pressure switch is used to detect low RCIC system pump suction pressure and is set to trip the RCIC turbine at ≤ 15 inches of mercury vacuum. This setpoint is chosen to prevent pump damage by cavitation.

3.2.C.5 Reactor Vessel Water Level High (Level 8)

A high reactor water level trip is indicative that the RCIC system has performed satisfactorily in providing makeup water to the reactor vessel. The reactor vessel high water level setting which trips the RCIC turbine is near the top of the steam separators and sufficiently low to prevent gross moisture carryover to the RCIC turbine. Two differential pressure transmitters trip to initiate a RCIC turbine shutdown. Once tripped the system is capable of automatic reset after the water level drops below Level 8. This automatic reset eliminates the need for manual reset of the system before the operator can take manual control to avoid fluctuating water levels.

6. RCIC System Flow

To prevent damage by overheating at reduced RCIC system pump flow, a pump discharge minimum flow bypass is provided. The bypass is controlled by an automatic, D. C. motor-operated valve. A high flow signal from a flow meter downstream of the pump on the main RCIC line will cause the bypass valve to close. Two signals are required to open the valve: A RCIC pump discharge pressure switch high pressure signal must be received to act as a permissive to open the bypass valve in the presence of a low flow signal from the flow switch.

Note:

Because the steam supply line to the RCIC turbine is part of the nuclear system process barrier, the following conditions (7 - 13) automatically isolate this line, causing shutdown of the RCIC system turbine.

7. RCIC Equipment Room Temperature High

High ambient temperature in the RCIC equipment room near the emergency area cooler could indicate a break in the RCIC system turbine steam line. The automatic closure of the RCIC steam line valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. The high temperature setting of 90 F + ambient was selected to be far enough above anticipated normal RCIC system operational levels to avoid spurious isolation but low enough to provide timely detection of a RCIC turbine steam line break. The high temperature trip initiates a timer which isolates the RCIC turbine steam line if the temperature is not reduced below the setpoint.

8. RCIC Steam Line Pressure Low

Low pressure in the RCIC steam supply could indicate a break in the RCIC steam line. Therefore, the RCIC steam line isolation valves are automatically closed. The steam line low pressure function is provided so that in the event a gross rupture of the RCIC steam line occurred upstream from the high flow sensing location, thus negating the high flow indicating function, isolation would be effected on low pressure. The iso-

3.2.C.8. RCIC Steam Line Pressure Low (Continued)

lation setpoint of 50 psig is chosen at a pressure below that at which the RCIC turbine can effectively operate.

9. RCIC Steam Line Flow (High)

RCIC turbine high steam flow could indicate a break in the RCIC turbine steam line. The automatic closure of the RCIC steam line isolation valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive materials from the nuclear system process barrier. Upon detection of RCIC turbine high steam flow the RCIC turbine steam line is isolated. The high steam flow trip setting of 300% flow was selected high enough to avoid spurious isolation, i.e., above the high steam flow rate encountered during turbine starts. The setting was selected low enough to provide timely detection of an RCIC turbine steam line break.

10. RCIC Turbine Exhaust Diaphragm Pressure High

High pressure in the RCIC turbine exhaust could indicate that the turbine rotor is not turning, thus allowing reactor pressure to act on the turbine exhaust line. The RCIC steam line isolation valves are automatically closed to prevent overpressurization of the turbine exhaust line. The turbine exhaust diaphragm pressure trip setting of 10 psig is selected high enough to avoid isolation of the RCIC if the turbine is operating, yet low enough to effect isolation before the turbine exhaust line is unduly pressurized.

11. Suppression Chamber Area Air Temperature High

As in the RCIC equipment room, and for the same reason, a temperature of 90 F + ambient will initiate a timer to isolate the RCIC turbine steam line.

12. Suppression Chamber Area Differential Air Temperature High

As for the RCIC equipment room differential temperature, and for the same reason, a high differential air temperature between the inlet and outlet ducts which ventilate the suppression chamber area will also initiate a timer to isolate the RCIC turbine steam line.

13. RCIC Logic Power Failure Monitor

The RCIC Logic Power Failure Monitor monitors the availability of power to the logic system. In the event of loss of availability of power to the logic system, an alarm is annunciated in the control room.

14. Condensate Storage Tank Level Low

The low CST level signal transfers RCIC suction from the CST to the suppression pool. The setpoint was chosen to ensure an uninterrupted supply of water during suction transfer.

15. Suppression Pool Water Level High

A high water level in the suppression chamber automatically switches RCIC suction from the CST to the suppression pool.

D. Instrumentation Which Initiates or Controls ADS (Table 3.2-4)

The ADS is a backup system to HPCI. In the event of its failure to maintain reactor water level, ADS will initiate depressurization of the reactor in time for LPCI and CS to adequately cool the core. Four signals are required to initiate ADS: Low water level, confirmed low water level, high drywell pressure, and either a RHR or Core Spray pump available. The simultaneous presence of these four signals will initiate a 120 second timer which will depressurize the reactor if not reset.

1. Reactor Vessel Water Level

a. Reactor Vessel Water Level Low (Level 3)

The second reactor vessel low water level initiation setting (+8.5 inches) is selected to confirm that water level in the vessel is in fact low, thus providing protection against inadvertent depressurization in the event of an instrument line (water level) failure. Such a failure could produce a simultaneous high drywell pressure. A confirmed low level is one of four signals required to initiate ADS.

b. Reactor Vessel Water Level Low Low Low (Level 1)

The reactor vessel low water level setting of -121.5 inches is selected to provide a permissive signal to open the relief valve and depressurize the reactor vessel in time to allow adequate cooling of the fuel by the core spray and LPCI systems following a LOCA in which the other make up systems (RCIC and HPCI) fail to maintain vessel water level. This signal is one of four required to initiate ADS.

2. Drywell Pressure High

A primary containment high pressure of ≥ 2 psig indicates that a breach of the nuclear system process barrier has occurred inside the drywell. The signal is one of four required to initiate the ADS.

3.2.D. 3. RHR Pump Discharge Pressure High

An RHR pump discharge pressure of ≥ 100 psig indicates that LPCI flow is available when the reactor is depressurized. The presence of this signal means low pressure core standby cooling is available. Low pressure core standby cooling available is one of the four signals required to initiate ADS.

4. Core Spray Pump Discharge Pressure High

A core spray pump discharge pressure of ≥ 100 psig indicates that Core Spray flow is available when the reactor is depressurized. The presence of this signal means low pressure core standby cooling is available. Low pressure core standby cooling available is one of the four signals required to initiate ADS.

5. Auto Depressurization Timer

The 120-second delay time setting is chosen to be long enough so that the HPCI system has time to start, yet not so long that the core spray system and LPCI are unable to adequately cool the core if HPCI fails to start. An alarm in the main control room is annunciated each time either of the timers is timing. Resetting the automatic depressurization system logic in the presence of tripped initiating signals recycles the timers.

6. Automatic Blowdown Control Power Failure Monitor

The Automatic Blowdown Control Power Failure Monitor monitors the availability of power to the logic system. In the event of loss of availability of power to the logic system, an alarm is annunciated in the control room.

E. Instrumentation Which Initiates or Controls the LPCI Mode of RHR (Table 3.2-5)

1. Reactor Vessel Water Level Low Low Low (Level 1)

Reactor vessel low water level (Level 1) initiates LPCI and indicates that the core is in danger of being overheated because of an insufficient coolant inventory. This level is sufficient to allow the timed initiation of the various valve closure and loop selection routines to go to completion and still successfully perform its design function.

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2. Drywell Pressure High

Primary containment high pressure is indicative of a break in the nuclear system process barrier inside the drywell. The high drywell pressure setpoint of ≤ 2 psig is selected to be high enough to avoid spurious starts but low enough to allow timely system initiation.

3. Reactor Vessel Steam Dome Pressure Low

The Bases for Reactor Pressure (Shutdown Cooling Mode) are discussed in the Bases for Specification 3.2.A.2.

With an analytical limit of ≥ 300 psig and a nominal trip setpoint of 360 psig, the recirculation discharge valve will close successfully during a LOCA condition.

Once the LPCI system is initiated, a reactor low pressure setpoint of 422 psig produces a signal which is used as a permissive to open the LPCI in-

3.2.E.9 Valve Selection Timers

After 10 minutes, a timer cancels the LPCI signals to the injection valves. The cancellation of the signals allows the operator to divert the water for other post-accident purposes. Cancellation of the signals does not cause the injection valves to move.

10. RHR Relay Logic Power Failure Monitor

The RHR Relay Logic Power Failure Monitor monitors the availability of power to the logic system. In the event of loss of availability of power to the logic system, an alarm is annunciated in the control room.

F. Instrumentation Which Initiates or Controls Core Spray (Table 3.2-6)

1. Reactor Vessel Water Level Low Low Low (Level 1)

A reactor low water level of -121.5 inches (Level 1) initiates Core Spray. This level is indicative that the core is in danger of being overheated because of an insufficient coolant inventory.

2. Drywell Pressure High

Primary containment high pressure is indicative of a break in the nuclear system process barrier inside the drywell. The high drywell pressure setpoint of ≤ 2 psig is selected to be high enough to avoid spurious system initiation but low enough to allow timely system initiation.

3. Reactor Vessel Steam Dome Pressure Low

Once the core spray system is initiated, a reactor low pressure setpoint of 422 psig produces a signal which is used as a permissive to open the core spray injection valves. The valves do not open, however, until reactor pressure falls below the discharge head of the core spray system.

4. Core Spray Sparger Differential Pressure

A detection system is provided to continuously confirm the integrity of the core spray piping between the inside of the reactor vessel and the core shroud. A differential pressure switch measures the pressure difference between the top of the core support plate and the inside of the core spray sparger pipe just outside the reactor vessel. If the core spray sparger piping is sound, this pressure difference will be the pressure drop across the core resulting from inter-channel leakage. If integrity is lost, this pressure drop will include the steam separator pressure drop. An increase in the normal pressure drop initiates an alarm in the main control room.

M. Instrumentation Which Initiates Energization by Onsite Power Sources (Table 3.2-13)

The undervoltage relays shall automatically trip the loss of offsite power (LOSP) lockout relays if voltage is lost on the emergency buses and low voltage is sensed on start-up transformer 1C (SUT 1C). This lockout will, if a loss of coolant accident (LOCA) has previously occurred, cause energization of the emergency 4160 volt buses by the Diesel Generators (D/Gs). If the LOSP and LOCA occur simultaneously, the lockout relay will provide a permissive allowing D/G output breaker closure when the D/G voltage is up to normal. The undervoltage relays will have no time delay. The absence of time delay provides a faster response time if the diesel generator has been previously initiated and prevents an additional time delay if it has not. This scheme prevents the connection of the D/G to the offsite power source.

N. Instrumentation Which Arms Low Low Set System (Table 3.2-14)

The bases for these trip functions are found in the bases for Section 3.6.H, page 3.6-21.

3.2.1 References

1. FSAR Appendix G, Plant Nuclear Safety Operational Analysis
2. FSAR Section 7.3, Primary Containment and Reactor Vessel Isolation Control System
3. FSAR Section 14, Plant Safety Analysis
4. FSAR Section 6, Core Standby Cooling Systems
5. FSAR Section 14.4.4, Refueling Accident
6. FSAR Section 6.5.3, Integrated Operation of the Core Standby Cooling Systems
7. FSAR Section 6.5.3.1, Liquid Line Breaks
8. 10 CFR 100

4.2 PROTECTIVE INSTRUMENTATION

The instrumentation listed in Tables 4.2-1 thru 4.2-13 will be functionally tested and calibrated at regularly scheduled intervals. The same design reliability goal as the Reactor Protection System of 0.99999 is generally applied for all applications of one-out-of-two-taken-twice logic. Therefore, on-off sensors are tested once every three months, and bi-stable trips associated with analog sensors and amplifiers are tested once per week. The ATTS instruments are tested once per month per NEDO-21617-A.

Those instruments which, when tripped, result in a rod block have their contacts arranged in a one-out-of-n logic, and all are capable of being bypassed. For such a tripping arrangement with bypass capability provided, there is an optimum test interval that should be maintained in order to maximize the reliability of a given channel (Reference 1). This takes account of the fact that testing degrades reliability and the optimum interval between tests is approximately given by:

$$i = \sqrt{\frac{2t}{r}}$$

Where: i = the optimum interval between tests.

t = the time the trip contacts are disabled from performing their function while the test is in progress.

r = the expected failure rate of the relays.

To test the trip relays requires that the channel be bypassed, the test made, and the system returned to its initial state. It is assumed this task requires an estimated 30 minutes to complete in a thorough and workmanlike manner and that the relays have a failure rate of 10^{-6} failures per hour. Using this data and the above operation, the optimum test interval is:

$$i = \sqrt{\frac{2(0.5)}{10^{-6}}} = 10^{3} \text{ hours}$$

$$\approx 42 \text{ days}$$

A test interval of once-per-month will be used initially.

The sensors and electronic apparatus have not been included here as these are analog devices with readouts in the control room and the sensors and electronic apparatus can be checked by comparison with other like instruments. The checks which are made on a daily or once per shift basis are adequate to assure operability of the sensors and electronic apparatus, and the test interval given above provides for optimum testing of the relay circuits.

The above calculated test interval optimizes each individual channel, considering it to be independent of all others. As an example, assume that there are two channels with an individual technician assigned to each. Each technician tests his channel at the optimum frequency, but the two technicians are not allowed to communicate so that one can advise the other that his channel is under test. Under these conditions, it is possible for both channels to be under test simultaneously. Now, assume that the technicians are required to communicate and that two

4.2 PROTECTIVE INSTRUMENTATION (Continued)

channels are never tested at the same time.

Forbidding simultaneous testing improves the availability of the system over that which would be achieved by testing each channel independently. These one out of n trip systems will be tested one at a time in order to take advantage of this inherent improvement in availability.

Optimizing each channel independently may not truly optimize the system considering the overall rules of system operation. However, true system optimization is a complex problem. The optimums are broad, not sharp, and optimizing the individual channels is generally adequate for the system.

The formula given above minimizes the unavailability of a single channel which must be bypassed during testing. The minimization of the unavailability is illustrated by Curve No. 1 of Figure 4.2-1 which assumes that a channel has a failure rate of 0.1×10^{-6}/hour and that 0.5 hours is required to test it. The unavailability is a minimum at a test interval i, of 3.16×10^{3} hours.

If two similar channels are used in a one-out-of-two configuration, test interval for minimum unavailability changes as a function of the rules for testing. The simplest case is to test each one independent of the other. In this case, there is assumed to be a finite probability that both may be bypassed at one time. This case is shown by Curve No.2. Note that the unavailability is lower as expected for a redundant system and the minimum occurs at the same test interval. Thus, if the two channels are tested independently, the equation on the preceding page yields the test interval for minimum unavailability.

A more usual case is that the testing is not done independently. If both channels are bypassed and tested at the same time, the result is shown in Curve No. 3. Note that the minimum occurs at about 40,000 hours, much longer than for Cases 1 and 2. Also, the minimum is not nearly as low as Case 2 which indicates that this method of testing does not take full advantage of the redundant channel. Bypassing both channels for simultaneous testing should be avoided.

The most likely case would be to stipulate that one channel be bypassed, tested, and restored, and then immediately following, the second channel be bypassed, tested, and restored. This is shown by Curve No. 4. Note that there is no true minimum. The curve does have a definite knee and very little reduction in system unavailability is achieved by testing at a shorter interval than computed by the equation for a single channel.

The best test procedure of all those examined is to perfectly stagger the tests. That is , if the test interval is four months, test one or the other channel every two months. This is shown in Curve No. 5. The difference between Cases 4 and 5 is negiligible. There may be other arguments, however, that more strongly support the perfectly staggered tests, including reductions in human error.

The conclusions to be drawn are these:

i. A one-out-of-n system may be treated the same as a single channel in terms of choosing a test interval; and

ii. More than one channel should not be bypassed for testing at any one time.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS

3.6.H.1. Relief/Safety Valves

a. When one or more relief/safety valve(s) is known to be failed an orderly shutdown shall be initiated and the reactor depressurized to less than 113 psig within 24 hours. Prior to reactor startup from a cold condition all relief/safety valves shall be operable.

b. With one or more relief/safety valve(s) stuck open, place the reactor mode switch in the shutdown position.

c. With one or more safety/relief valve tailpipe pressure switches of a safety/relief valve declared inoperable and the associated safety/relief valve(s) otherwise indicated to be open, place the reactor mode switch in the Shutdown position.

d. With one safety/relief valve tailpipe pressure switch of a safety/relief valve declared inoperable and the associated safety/relief valve(s) otherwise indicated to be closed, plant operation may continue. Remove the function of that pressure switch from the low low set logic circuitry until the next COLD SHUTDOWN. Upon COLD SHUTDOWN, restore the pressure switch(es) to OPERABLE status before STARTUP.

e. With both safety/relief valve tailpipe pressure switches of a safety/relief valve declared inoperable and the associated safety/relief valve(s) otherwise indicated to be closed, restore at least one inoperable switch to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

4.6.H.1. Relief/Safety Valves

a. End of Operating Cycle

Approximately one-half of all relief/safety valves shall be benchchecked or replaced with a benchchecked valve each refueling outage. All 11 valves will have been checked or replaced upon the completion of every second operating cycle.

b. Each Operating Cycle

Once during each operating cycle, at a reactor pressure > 100 psig each relief valve shall be manually opened until thermocouples downstream of the valve indicate steam is flowing from the valve.

c. Integrity of Relief Valve Bellows*

The integrity of the relief valve bellows shall be continuously monitored and the pressure switch calibrated once per operating cycle and the accumulators and air piping shall be inspected for leakage once per operating cycle.

d. Relief Valve Maintenance

At least one relief valve shall be disassembled and inspected each operating cycle.

e. Operability of Tail Pipe Pressure Switches

The tail pipe pressure switch of each relief/safety valve shall be demonstrated operable by performance of a:

1. Functional Test:

   a. At least once per 31 days, except that all portions of instrumentation inside the primary containment may be excluded from the functional te t, and

*Does not apply to two-stage Target Rock SRVs

4.6.H.1 Relief/Safety Valves (Continued)

a. Operability of Tail Pipe Pressure Switches

1. Functional Test:

b. At each scheduled outage greater than 72 hours during which entry is made into the primary containment, if not performed within the previous 31 days.

2. Calibration and verifying the setpoint to be 85, +15, -5 psig at least once per 18 months.

3.6.H.2 Relief/Safety Valves Low Low Set Function

During power operation startup, and hot standby, the relief valve function and the low low set function of the following reactor coolant system safety/relief valves shall be OPERABLE with the following low low set function lift settings:

Low Low Set Valve Function	Allowable Value (psig)* Open	Close
Low	≤ 1005	≤ 857
Medium	≤ 1020	≤ 872
Medium High	≤ 1035	≤ 887
High	≤ 1045	≤ 897

a. With the relief valve function and/or the low low set function of one of the above required reactor coolant system safety/relief valves inoperable, restore the relief valve function and the low low set function to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and COLD SHUTDOWN within the following 24 hours.

4.6.H.2 Relief/Safety Valves Low Low Set Function

The low low set relief valve function and the low low set function pressure actuation instrumentation shall be demonstrated OPERABLE by performance of a:

a. CHANNEL FUNCTIONAL TEST, including calibration of the trip unit and the dedicated high steam dome pressure channels**, at least once per month.

b. CHANNEL CALIBRATION, Logic System Functional Test, and simulated automatic operation of the entire system at least once per 18 months.

* The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.

** The setpoint for dedicated high steam dome pressure channels is ≤ 1054 psig.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS

b. With the relief valve function and/or the low low set function of more than one of the above required reactor coolant system relief/safety valves inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

3.6.I Jet Pumps

Whenever the reactor is in the Start & Hot Standby or Run Mode with both recirculating pumps operating, all jet pumps shall be operable. If it is determined that a jet pump is inoperable, an orderly shutdown shall be initiated and the reactor shall be in the Cold Shutdown Condition within 24 hours.

4.6 I. Jet Pumps

Whenever both recirculating pumps are operating with the reactor in the Start & Hot Standby or Run Mode, jet pump operability shall be checked daily by verifying that the following conditions do not occur simultaneously.

1. The two recirculation loops have a flow imbalance of 15% or more when the pumps are operated at the same speed.

3.6.H. Relief/Safety Valves (Continued)

Experience in relief/safety valve operation shows that a testing of 50 percent of the valves per year is adequate to detect failure or deteriorations. The relief/safety valves are benchtested every second operating cycle to ensure that their set points are within the tolerance given in Specification 2.2.A. The relief/safety valves are tested in place at low reactor pressure once per operating cycle to establish that they will open and pass steam.

The requirements established above apply when the nuclear system can be pressurized above ambient conditions. These requirements are applicable at nuclear system pressures below normal operating pressures because abnormal operational transients could possibly start at these conditions such that eventual overpressure relief would be needed. However, these transients are much less severe in terms of pressure, than those starting at rated conditions. The valves need not be functional when the vessel head is removed, since the nuclear system cannot be pressurized.

The low low set (LLS) system lowers the opening and closing setpoints on four preselected relief/safety valves. The LLS system lowers the setpoints after any relief/safety valve has opened at its normal steam pilot setpoint when a concurrent high reactor vessel steam dome pressure scram signal is present. The purpose of the LLS is to mitigate the induced high frequency loads on the containment and thrust loads on the SRV discharge line. The LLS system increases the amount of reactor depressurization during a relief/safety valve blowdown because the lowered LLS setpoints keep the four selected LLS relief/safety valves open for a longer time. The high reactor vessel steam dome pressure signal for the LLS logic is provided by the exclusive analog trip channels. The purpose of installing special dedicated steam dome pressure channels is to maintain separation from the RPS high pressure scram functions.

I. Jet Pumps

Failure of a jet pump nozzle assembly hold down mechanism, nozzle assembly and/or riser, would increase the cross-sectional flow area for blowdown following the design basis double-ended line break. Therefore, if a failure occurred, repairs must be made.

The detection technique is as follows. With the two recirculation pumps balanced in speed to within ± 5%, the flow rates in both recirculation loops will be verified by control room monitoring instruments. If the two flow rate values do not differ by more than 10%, riser and nozzle assembly integrity has been verified. If they do differ by 10% or more, the core flow rate measured by the jet pump diffuser differential pressure system must be checked against the core flow rate derived from the measured values of loop flow to core flow correlation. If the difference between measured and derived core flow rate is 10% or more (with the derived value higher) diffuser measurements will be taken to define the location within the vessel of failed jet pump nozzle (or riser) and the plant shut down for repairs.

3.6.I. Jet Pumps (Continued)

If the potential blowdown flow area is increased, the system resistance to the recirculation pump is also reduced; hence, the affected drive pump will "run out" to a substantitally higher flow rate (approximately 115% to 120% for a single nozzle failure). If the two loops are balanced in flow at the same speed, the resistance characteristics cannot have changed. Any imbalance between drive loop flow rates would be indicated by the plant process instrumentation. In addition, the affected jet pump would provide a leakage path past the core thus reducing the core flow rate. The reverse flow through the inactive jet pump would still be indicated by a positive differential pressure but the net effect would be a slight decrease (3% to 6%) in the total core flow measured. This decrease, together with the loop flow increase, would result in a lack of correlation between measured and derived core flow rate. Finally, the affected jet pump diffuser differential pressure signal would be reduced because the backflow would be less than the normal forward flow.

A nozzle-riser system failure could also generate the coincident failure of a jet pump body; however, the converse is not true. The lack of any substantial stress in the jet pump body makes failure impossible without an initial nozzle riser system failure.

3.6.J Recirculation Pump Speeds

An evaluation was not provided for ECCS performance during reactor operation with one recirculation loop out-of-service. Therefore, continuous reactor operation under such conditions should not be permitted until the necessary analyses have been performed, evaluated and determined acceptable. The reactor may, however, operate for periods up to 24 hours with one recirculation loop out-of-service. This short time period permits corrective action to be taken and minimizes unnecessary shutdowns which is consistent with other Technical Specifications. During this period of time the reactor will be operated within the restrictions of the thermal analysis and will be protected from fuel damage resulting from anticipated transients.

TABLE 3.7-1

PRIMARY CONTAINMENT ISOLATION VALVES

Isolation Group (b)	Valve Identification (d)	Number of Power Operated Valves Inside	Outside	Maximum Operating Time (sec)	Normal Position (a)	Action on Initiating Signal (a)
2	Suppression chamber exhaust valve bypass to standby gas treatment (T48-F339, T48-F338)		2	5	C	SC
2	Suppression chamber nitrogen make-up line (normal operation) (T48-F118B)		1	5	O	GC
2	Drywell and suppression chamber nitrogen supply line (inerting) (T48-F103)		1	5	C	SC
2	Drywell and suppression chamber nitrogen make-up line (normal operation) (T48-F104)		1	5	C	SC
2	Drywell equipment drain sump discharge (G11-F019, G11-F020)		2	15	C	SC
2	Drywell floor drain sump discharge (G11-F003, G11-F004)		2	15	C	SC
2	TIP Guide Tube (C51-J004)		1 each line	NA	C	SC
(c)	Drywell pneumatic system (P70-F002, P70-F003)		2	5	O	GC
6	RHR reactor shutdown cooling suction (supply) (E11-F008, E11-F009)	1	1	24	C	SC

TABLE 3.7-1 (Cont'd)

PRIMARY CONTAINMENT ISOLATION VALVES

Isolation Group (b)	Valve Identification (d)	Number of Power Operated Valves Inside	Outside	Maximum Operating Time (sec)	Normal Position (a)	Action on Initiating Signal (a)
6	RHR reactor head spray (E11-F022, E11-F023)	1	1	20	C	SC
3	HPCI - turbine steam (E41-F002, E41-F003)	1	1	50	0	GC
4	RCIC - turbine steam (E51-F007, E51-F008)	1	1	20	0	GC
5	Reactor water cleanup from recirculation loop (G31-F001, G31-F004)	1	1	30	0	GC

(e)	Check Valve Identification	Number of Valves Inside	Outside	(e)	Normal Position	(e)
	Feedwater (B21-F010 A,B; B21-F032A,B)	2	2		0	
	Control Rod Hydraulic Return (C11-F083, C11-F086)	1	1		0	
	Standby Liquid Control System (C41-F007, C41-F006)	1	1		C	
	Reactor water cleanup return line (G31-F039)		1		0	
	RHR injection testable check (E11-F050 A,B)	2			C	

Table 3.7-1
(Concluded)

Primary Containment Isolation Valves

These notes refer to the lower case letters in parentheses on the previous page.

NOTES:

a. Key: O = Open SC = Stays closed
C = Closed GC = Goes closed

b. Isolation Groupings are as follows:

GROUP 1: The valves in Group 1 are actuated by any one of the following conditions:

1. Reactor vessel water level Low Low Low (Level 1)
2. Main steam line radiation high
3. Main steam line flow high
4. Main steam line tunnel temperature high
5. Main steam line pressure low
6. Condenser vacuum low

GROUP 2: The valves in Group 2 are actuated by any one of the following conditions:

1. Reactor vessel water level low (Level 3)
2. Drywell pressure high

GROUP 3: Isolation valves in the high pressure coolant injection (HPCI) system are actuated by any one of the following conditions:

1. HPCI steam line flow high
2. High temperature in the vicinity of the HPCI steam line
3. HPCI steam line pressure low
4. HPCI turbine exhaust diaphragm pressure

GROUP 4: Primary Containment Isolation valves in the reactor core isolation cooling (RCIC) system are actuated by any one of the following conditions:

1. RCIC steam line flow high
2. High temperature in the vicinity of the RCIC steam line
3. RCIC steam line pressure low

GROUP 5: The valves in Group 5 are actuated by any one of the following conditions:

1. Reactor vessel water level Low Low (Level 2)
2. Reactor water cleanup equipment room temperature high
3. Reactor water cleanup equipment room ventilation differential temperature high
4. Reactor water cleanup system differential flow high
5. Actuation of Standby Liquid Control System - closes outside valve only
6. High temperature following non-regenerative heat exchanger - closes outside valve only

GROUP 6: The valves in Group 6 are actuated by the following conditions:

1. Reactor vessel water level low (Level 3)
2. Reactor vessel steam dome pressure high (shutdown cooling mode)

c. Requires a Group 2 signal or a Reactor Building ventilation high radiation isolation signal.

d. For redundant lines, only one set of valves is listed. Other sets are identical except for valve numbers, which are included. Valve numbers are listed in order from within primary containment outward for each line.

e. Not applicable to check valves.

Notes to Table 3.7-1 (Concluded)

For all entries in Table 3.7-1 where the number of isolation valves is equal to one outside containment and none inside containment the valve is in a series path with at least one other containment isolation valve in the Table. For example, T48-F118 is in a series path with T48-F104, thus providing two in series power operated containment isolation valves.

3.7.D. Primary Containment Isolation Valves

Double isolation valves are provided on lines penetrating the primary containment and open to the free space of the containment. Closure of one of the valves in each line would be sufficient to maintain the integrity of the system. Automatic initiation is required to minimize the potential leakage paths from the containment in the event of a loss-of-coolant accident.

Table 3.7-1 contains primary containment isolation valves that automatically actuate on a primary containment isolation signal. The primary containment isolation signals are grouped as described below.

Group 1 process lines are isolated by reactor vessel water level low low low (Level 1) in order for removal of decay heat subsequent to a scram, yet isolate in time for proper operation of the core standby cooling systems.

Group 2 isolation valves are not normally in use and are closed by reactor vessel water level low (Level 3) or drywell pressure high. It is not desirable to actuate the Group 2 isolation signal by a transient or spurious signal.

Group 3 and 4 process lines are designed to remain operable and mitigate the consequences of an accident which results in the isolation of other process lines. The signals which initiate isolation of Group 3 and 4 process lines are therefore indicative of a condition which would render these other lines inoperable.

Group 5 process lines are normally in use and it is therefore not desirable to cause spurious isolation due to high drywell pressure resulting from non-safety related causes. To protect the reactor from a possible pipe break in the system, isolation is provided by high temperature in the cleanup system area or high flow difference through the cleanup system. Also since the vessel could potentially be drained through the cleanup system, a low level isolation is provided.

Group 6 isolation valves are not normally in use and are closed by reactor vessel water level low (Level 3) and reactor steam dome pressure low permissive.

The primary containment is penetrated by several small diameter instrument lines connected to the reactor coolant system. Each instrument line contains a 0.25 inch restricting orifice inside the primary containment, a manually operated root valve outside the primary containment, and an excess flow check valve outside the primary containment.

3.7.E. References

1. Bodega Bay Preliminary Hazards Summary Report, Appendix 1, Docket No. 50-205, December 28, 1962.
2. Robbins, C. H. "Tests of a Full Scale 1/48 Segment of the Humboldt Bay Pressure Suppression Containment", GEAP-3596, November 17, 1960.
3. FSAR Section 5, Containment Systems.
4. TID 14844, "Calculation of Distance Factors for Power and Test Reactor Sites", J.J. DiNunno et al., March 23, 1962, USAEC Division of Licensing and Regulation.
5. 10 CFR 100, "Reactor Site Criteria", 27 Federal Register 3509, April 12, 1962.