5.0 REACTOR COOLANT SYSTEM

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5.1 SUMMARY DESCRIPTION

The Reactor Coolant System (RCS) shown in Figure 5.1-1, Sheets 1 and 2 consist of similar heat transfer loops connected in parallel to the reactor pressure vessel. Each loop contains a reactor coolant pump, steam generator and associated piping and valves. In addition, the system includes a pressurizer, a pressurizer relief tank, interconnecting piping and instrumentation necessary for operational control. All the above components are located in the Containment Building.

During operation, the RCS transfers the heat generated in the core to the steam generators where steam is produced to drive the turbine generator. Borated demineralized water is circulated in the RCS at a flow rate and temperature consistent with achieving the reactor core thermal-hydraulic performance. The water also acts as a neutron moderator and reflector, and as a solvent for the neutron absorber used in chemical shim control.

The RCS pressure boundary provides a barrier against the release of radioactivity generated within the reactor, and is designed to ensure a high degree of integrity throughout the life of the plant.

RCS pressure is controlled by the use of the pressurizer where water and steam are maintained in equilibrium by electrical heaters and water sprays. Steam can be formed (by the heaters) or condensed (by the pressurizer spray) to minimize pressure variations due to contraction and expansion of the reactor coolant. Spring loaded safety valves and a power operated relief valve are mounted on the pressurizer and discharge to the pressurizer relief tank, where the steam is condensed and cooled by mixing with water.

Reactor coolant system high point vents are provided on the reactor vessel head and on the pressurizer (see Figure 5.1-1). These vents are designed to vent noncondensible gases which may inhibit core cooling during natural circulation. Venting is directly to open areas of the Containment to assure good mixing with the containment air. The vents are sized to limit the required makeup flow rate to within the capability of the Chemical and Volume Control System.

The extent of the RCS is defined as:

1. The reactor vessel including control rod drive mechanism housings.

2. The reactor coolant side of the steam generators.

3. The reactor coolant pumps up to and including the number 1 seal.

4. A pressurizer attached to one of the reactor coolant loops.

5. The pressurizer relief tank.

6. The safety and relief valves.

7. The interconnecting piping, valves and fittings between the principal components listed above.

8. The piping, fittings and valves leading to connecting auxiliary or support systems up to and including either: 1) a 3/8 inch inside diameter flow restrictor, or 2) the second of two isolation valves either normally closed or capable of automatic or remote manual closure.

Reactor Coolant System Components

Reactor Vessel

The reactor vessel is cylindrical, with a welded hemispherical bottom head and a removable, flanged and gasketed, hemispherical upper head. The vessel contains the core, core supporting structures, control rods and other parts directly associated with the core.

The vessel has inlet and outlet nozzles located in a horizontal plane just below the reactor vessel flange but above the top of the core. Coolant enters the vessel through the inlet nozzles and flows down the core barrel-vessel wall annulus, turns at the bottom and flows up through the core to the outlet nozzles.

Steam Generators

The steam generators are vertical shell and U-tube evaporators with integral moisture separating equipment. The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the steam generator. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel.

Reactor Coolant Pumps

The reactor coolant pumps are identical single-speed centrifugal units driven by air-cooled, three-phase induction motors. The shaft is vertical with the motor mounted above the pumps. A flywheel on the shaft above the motor provides additional inertia to extend pump coastdown. The inlet is at the bottom of the pump; discharge is on the side.

Piping

The reactor coolant loop piping is specified in sizes consistent with system requirements.

The hot leg inside diameter is 29 inches and the inside diameter of the cold leg return line to the reactor vessel is 27-1/2 inches. The piping between the steam generator and the pump suction is increased to 31 inches in inside diameter to reduce pressure drop and improve flow conditions to the pump suction.

Pressurizer

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads. Electrical heaters are installed through the bottom head of the vessel while the spray nozzle, relief and safety valve connections are located in the top head of the vessel.

Pressurizer Relief Tank

The pressurizer relief tank is a horizontal, cylindrical vessel with hemispherical ends. Steam from the pressurizer safety and relief valves is discharged into the pressurizer relief tank through a sparger pipe under the water level. This condenses and cools the steam by mixing it with water that is near ambient temperature.

Safety and Relief Valves

The pressurizer safety valves are of the totally enclosed pop-type. The valves are spring loaded, self-activated with back-pressure compensation. The power operated relief valves limit system pressure for large power mismatch. They are operated automatically or by remote manual control. Remotely operated valves are provided to isolate the inlet to the power operated relief valves if excessive leakage occurs.

High Point Vent Valves

The high point vent valves are solenoid type and are operated by remote manual control from the Control Room.

Reactor Coolant System Performance Characteristics

Tabulations of important design and performance characteristics of the RCS are provided in Table 5.1-1.

Reactor Coolant Flow

The reactor coolant flow, a major parameter in the design of the system and its components, is established with a detailed design procedure supported by operating plant performance data, by pump model tests and analysis, and by pressure drop tests and analyses of the reactor vessel and fuel assemblies. Though data from all operating plants have indicated that the actual flow has been well above the flow specified for the thermal design of the plant, the following is provided for monitoring for postulated flow reductions:

1. Technical Specification requirements to verify RCS flow and to perform calorimetric power checks;

2. For global flow changes:

   a. Flow meter on each RCS loop

   b. Inconsistencies between RCS temperatures and reactor power;

3. For local flow changes, inconsistencies in the incore flux map and/or the core exit thermocouple temperature indications.

By applying the design procedure described below, it is possible to specify the expected operating flow with reasonable accuracy.

Three reactor coolant flow rates are identified for the various plant design considerations. The definitions of these flows are presented in the following paragraphs. Many of the original plant design parameters were based on these flow rates. Actual flow rates may differ. See Chapter 15 for current values of the thermal design flow rate.

Best Estimate Flow

The best estimate flow is the calculated value predicted to occur for the actual plant operating condition. This flow is based on the best estimate of the reactor vessel, steam generator and piping flow resistance, and on the best estimate of the reactor coolant pump head-flow capacity, with no uncertainties assigned to either the system flow resistance or the pump head. The effects of differences in resistance due to changes in fuel assembly designs or other components are considered when necessary. System pressure drops, based on best estimate flow, are presented in Table 5.1-1. Although the best estimate flow is the value expected to occur in operation, more conservative flow rates are applied in some of the thermal and mechanical designs.

Thermal Design Flow

Thermal design flow is the basis for the reactor core thermal performance, the steam generator thermal performance, and the nominal plant parameters used throughout the design. To provide the required margin, the thermal design flow accounts for the uncertainties in reactor vessel, steam generator and piping flow resistances, reactor coolant pump head, and the methods used to measure flow rate. The thermal design flow is confirmed when the plant is placed in operation. Tabulations of important design and performance characteristics of the RCS as provided in Table 5.1-1 are based on the thermal design flow.

Mechanical Design Flow

Mechanical design flow is the conservatively high flow used in the mechanical design of the reactor vessel internals and fuel assemblies. To assure that a conservatively high flow is specified, the mechanical design flow is based on a reduced system resistance and on increased pump head capability. The mechanical design flow is greater than the best estimate flow.

Pump overspeed, due to a turbine generator overspeed of 20 percent, results in a peak reactor coolant flow of 120 percent of the mechanical design flow. The overspeed condition is applicable only to operating conditions when the reactor and turbine generator are at power.

Flows with One Pump Shutdown

The design procedure for calculation of flows with one pump shutdown is similar to the procedure described above for calculating flows with all pumps operating. For the case where reverse flow exists in the idle loop, the system resistance incorporates the idle loop with a locked rotor pump impeller reverse flow resistance as a flow path in parallel with the reactor vessel internals. The thermal design flow uncertainty includes a conservative application of parallel flow uncertainties (reactor internals high, idle loop low) as well as the usual component, pump and flow measurement uncertainties, thereby resulting in a conservatively low reactor flow rate for the thermal design. The mechanical design flow uncertainty is increased slightly to account for the slightly higher uncertainties at the higher pump flows.

Interrelated Performance and Safety Functions

The interrelated performance and safety functions of the RCS and its major components are listed below:

1. The RCS provides sufficient heat transfer capability to transfer the heat produced during power operation and when the reactor is subcritical, including the initial phase of plant cooldown, to the Steam and Power Conversion System.

2. The system provides sufficient heat transfer capability to transfer the heat produced during the subsequent phase of plant cooldown and cold shutdown to the Residual Heat Removal System.

3. The system heat removal capability under power operation and normal operational transients, including the transition from forced to natural circulation, shall assure no fuel damage within the operating bounds permitted by the Reactor Control and Protection Systems.

4. The RCS provides the water used as the core neutron moderator and reflector and as a solvent for chemical shim control.

5. The system maintains the homogeneity of soluble neutron poison concentration and rate of change of coolant temperature such that uncontrolled reactivity changes do not occur.

6. The reactor vessel is an integral part of the RCS pressure boundary and is capable of accommodating the temperatures and pressures associated with the operational transients. The reactor vessel functions to support the reactor core and control rod drive mechanisms.

7. The pressurizer maintains the system pressure during operation and limits pressure transients. During the reduction or increase of plant load, reactor coolant volume changes are accommodated in the pressurizer via the surge line.

8. The reactor coolant pumps supply the coolant flow necessary to remove heat from the reactor core and transfer it to the steam generators.

9. The steam generators provide high quality steam to the turbine. The tube and tubesheet boundary are designed to prevent or control to acceptable levels the transfer of activity generated within the core to the secondary system.

10. The RCS piping serves as a boundary for containing the coolant under operating temperature and pressure conditions and for limiting leakage (and activity release) to the Containment atmosphere. The RCS piping contains demineralized borated water which is circulated at the flow rate and temperature consistent with achieving the reactor core thermal and hydraulic performance.

5.1.1 SCHEMATIC FLOW DIAGRAM

The RCS is shown schematically in Figure 5.1-2. Included on this figure is a tabulation of principal pressures, temperatures, and the flow rate of the system under normal steady state full

power operating conditions. These parameters are based on the best estimate flow at the pump discharge. RCS volume under the above conditions is presented in Table 5.1-1.

5.1.2 PIPING AND INSTRUMENTATION DIAGRAM

A simplified version of the piping and instrumentation diagram of the RCS is shown on Figure 5.1-1, Sheets 1 and 2. The diagrams show the extent of the systems located within the Containment, and the points of separation between the RCS and the secondary (heat utilization) system. As part of the Reactor Coolant System, the four reactor coolant system wide range pressure sensors (PT403, PT437, PT3616 and PT405) are installed as depicted on Figure 5.1-1 Sheet 1, and are inside Containment as shown. One of these sensors is Veritrak Model 76 (PH2); the others are Rosemount Model 1154SH.

5.1.3 ELEVATION DRAWING

The components of the RCS are surrounded by concrete structures which provide support, radiation shielding and missile protection.

A detailed plant elevation drawing illustrating principal dimensions of the RCS in relation to the surrounding concrete structures is shown in Figure 5.1-3.

RCS shielding permits limited access to the Containment during power operation. The reactor vessel is installed in a thick concrete cavity formed by the primary shield. The entire RCS is enclosed by the secondary shield.

TABLE 5.1-1A (Unit 1)
SYSTEM DESIGN AND OPERATING PARAMETERS

(Sheet 1 of 2)

Plant design life, (years)	40
RCS design pressure, (psig)	2,485
Nominal operating pressure, (psig)	2,235
Total system volume including pressurizer and surge line, (ft^3)	13,400
System liquid volumes, including pressurizer water at maximum guaranteed power, (ft^3)	12,600
System water and steam volume at nominal Tavg of 589.5ºF, (ft^3)	12,135 ± 100
System design temperature, (except Pressurizer) ºF	650
Pressurizer design temperature, ºF	680
Pressurizer spray rate, maximum (gpm)	900
Pressurizer heater capacity, (kW)	1,800
Pressurizer relief tank volume, (ft^3)	1,800

SYSTEM THERMAL AND HYDRAULIC DATA - 3475MWt

	T_{AVG} = 589.2ºF[(a)(b)]	T_{AVG} = 574.2ºF[(a)(b)]
NSSS power (Mwt)	3,475	3,475
Reactor power, (MWt)	3,458	3,458
Thermal design flows, (gpm)		
Active loop	95,700	95,700
Reactor	382,800	382,800
Total reactor flow, (10^6 lb/hr)	142.0	145.2

TABLE 5.1-1A (Unit 1)
SYSTEM DESIGN AND OPERATING PARAMETERS

(Sheet 2 of 2)

Temperatures, (°F)		
Reactor vessel outlet	619.2	605.0
Reactor vessel inlet	559.2	543.5
Steam generator outlet	558.9	543.1
Steam generator steam	547.1	530.9
Feedwater	390/444.6	390/444.6 390/444.6
Steam pressure, (psia)	1021	892
Total steam flow, (10^6 lb/hr)	14.35/15.46	14.27/15.37
Best estimate flows, (gpm)		
Active loop	102,500	102,500
Reactor	410,000	410,000
Mechanical design flows, (gpm)		
Active loop	109,000	109,000
Reactor.	436,000	436,000

SYSTEM PRESSURE DROPS - 3475 MWt[(a)]

	17 x 17 OFA	RFAw/1FMs
Reactor vessel P, (psi)	49.5	51.5
Steam generator P, (psi)	33.7	33.2
Hot leg piping P, psi	1.3	1.3
Pump suction piping P, (psi)	3.4	3.3
Cold leg piping P, (psi)	3.6	3.5
Pump head, (feet)	279	283

a) 0% SGTP

b) Parameters bound both current WEC 17x17 OFA and RFA with IFMs fuel. RFA fuel may be implemented in the future.

TABLE 5.1-1B (Unit 2)
SYSTEM DESIGN AND OPERATING PARAMETERS

(Sheet 1 of 2)

Plant design life, (years)	40
RCS design pressure, (psig)	2,485
Nominal operating pressure, (psig)	2,235
Total system volume including pressurizer and surge line, (ft^3)	12,500
System liquid volumes, including pressurizer water at maximum guaranteed power, (ft^3)	12,000
System water and steam volume at nominal Tavg of 589.5ºF, (ft^3)	12,135 ± 100
System design temperature, (except Pressurizer) ºF	650
Pressurizer design temperature, ºF	680
Pressurizer spray rate, maximum (gpm)	900
Pressurizer heater capacity, (kW)	1,731
Pressurizer relief tank volume, (ft^3)	1,800

SYSTEM THERMAL AND HYDRAULIC DATA

	4 Pumps Running
NSSS power (Mwt)	3,474
Reactor power, (MWt)	3,458
Thermal design flows, (gpm)	
Active loop	95,700
Idle loop	-
Reactor	382,800
Total reactor flow, (10^6 lb/hr)	142.0

TABLE 5.1-1B (Unit 2)
SYSTEM DESIGN AND OPERATING PARAMETERS

(Sheet 2 of 2)

Temperatures, (°F)	
Reactor vessel outlet	618.8
Reactor vessel inlet	559.6
Steam generator outlet	559.3
Steam generator steam	544.6
Feedwater	441.5
Steam pressure, (psia)	995
Total steam flow, (10^6 lb/hr)	15.36
Best estimate flows, (gpm)	
Active loop	100,800
Idle loop	-
Reactor	402,000
Mechanical design flows, (gpm)	
Active loop	109,000
Idle loop	-
Reactor.	424,000

SYSTEM PRESSURE DROPS

Reactor vessel P, (psi)	46.5
Steam generator P, (psi)	38.0
Hot leg piping P, psi	1.3
Pump suction piping P, (psi)	3.3
Cold leg piping P, (psi)	3.3
Pump head, (feet)	287

5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY

Per Regulatory Guide 1.70, Revision 2, this section presents a discussion of the measures employed to provide and maintain the integrity of the reactor coolant pressure boundary (RCPB) for the plant design lifetime. In this context, the RCPB is as defined in Section 50.2 of 10CFR50. In that definition, the RCPB extends to the outermost Containment isolation valve in system piping which penetrates the Containment and is connected to the Reactor Coolant System (RCS). Since other sections of this report already describe the components of these auxiliary fluid systems in detail, the discussions in this section will be limited to the components of the RCS as defined in Section 5.1, unless otherwise noted.

For additional information on the RCS and for components which are part of the RCPB (as defined in 10CFR50.) but are not described in this section, refer to the following sections:

Section 6.3 - For discussions of the RCPB components which are part of Emergency Core Cooling System.

Section 9.3.4 - For discussions of the RCPB components which are part of the Chemical and Volume Control System.

Section 3.9N.1 - For discussions of the design loadings, stress limits, and analyses applied to the RCS and American Society of Mechanical Engineers (ASME) Code Class 1 components.

Section 3.9N.3 - For discussions of the design loadings, stress limits and analyses applied to ASME Code Class 2 and 3 components.

The phrase, RCS, as used in this section is as defined in Section 5.1. When the term RCPB is used in this section, its definition is that of Section 50.2 of 10CFR50.

5.2.1 COMPLIANCE WITH CODES AND CODE CASES

5.2.1.1 Compliance with 10CFR Section 50.55a

RCS components are designed and fabricated in accordance with the rules of 10CFR50., Section 50.55a, “Codes and Standards” except as described below. The actual addenda of the ASME Code applied in the design of each component is listed in Table 5.2-1.

All components located within the reactor coolant pressure boundary (as defined by 10CFR50.2) are Safety Class 1 as required by 10CFR50.55a with the exception of the 3/4” instrument lines and other 3/4” piping connected to the pressurizer above the normal water level and the pressurizer relief and safety valve discharge line. A rupture of one of these lines may result in a rapid depressurization of the reactor coolant system and ECCS actuation on low pressurizer pressure. Relief from the requirements of 10CFR50.55a was authorized by the NRC in accordance with 10CFR50.55a(a)(c)(ii). [8]

5.2.1.2 Applicable Code Cases

Regulatory Guides 1.84 and 1.85 are discussed in Appendix 1A, and Regulatory Guide 1.147. Code Cases N-20-4, 2124-1 and 2143-1 were used in the manufacture of the Unit 1 RSGs.

Prior to the implementation date of Regulatory Guide 1.85, Code Case 1528, which is not included in the Regulatory Guide 1.85 list of Nuclear Regulatory Commission (NRC) endorsed code cases, was used in the manufacture of the Comanche Peak Nuclear Power Plant (CPNPP) steam generators (Unit 2). Westinghouse is conducting a test program and compiling data which demonstrates the adequacy of Code Case 1528 material. Preliminary results of the test program (for review) and a request for approval of the use of Code Case 1528 have been submitted to the NRC via Reference [1].

A list of all Code Cases used on Safety Class 1 components within the Reactor Coolant Pressure Boundary is provided in Table 5.2-7.

5.2.2 OVERPRESSURE PROTECTION

RCS overpressure protection is accomplished by the utilization of safety valves along with the Reactor Protection System and associated equipment. Combinations of these systems provide compliance with the overpressure requirements of the ASME Code, Section III, paragraphs NB-7300 and NC-7300, for pressurized water reactor systems.

Auxiliary or emergency systems connected to the RCS are not utilized for prevention of RCS overpressurization.

5.2.2.1 Design Bases

Overpressure protection is provided for the RCS by the pressurizer safety valves which discharge to the pressurizer relief tank by common header. The transient on which the design requirements are set for the primary system overpressure protection is a complete loss of steam flow to the turbine with credit taken for steam generator safety valve operation and main feedwater flow maintained. However, for the sizing of the pressurizer safety valves, no credit is taken for reactor trip nor the operation of the following:

1. Pressurizer power operated relief valves.

2. Steam line relief valve.

3. Steam Dump System.

4. Reactor Control System.

5. Pressurizer Level Control System.

6. Pressurizer spray valve.

For this transient, the peak RCS and peak steam system pressure must be limited to 110 percent of their respective design values.

Assumptions for the overpressure analysis include: 1) the plant is operating at the power level corresponding to the engineered safeguards design rating, and 2) the RCS average temperature and pressure are at their maximum values. These are the most limiting assumptions with respect to system overpressure.

Overpressure protection for the steam system is provided by steam generator safety valves. The steam system safety valve capacity is based on providing enough relief to remove 105 percent of the engineered safeguards design steam flow. This must be done by limiting the maximum steam system pressure to less than 110 percent of the steam generator shell side design pressure.

Blowdown and heat dissipation systems of the Nuclear Steam Supply System (NSSS) connected to the discharge of these pressure relieving devices are discussed in Section 5.4.11.

Steam generator blowdown systems for the balance of plant are discussed in Section 10.4.8.

Postulated events and transients on which the design requirements of the overpressure protection system are based and discussed in Reference [2].

The criterion for sizing the pressurizer and steam generator safety valves is presented in Reference 2 in Chapter 2. Differences in plant parameters between CPNPP and Reference 2 are shown in Table 5.2- 6. Due to these differences, the transient analysis results will change. Chapter 15 of the CPNPP FSAR presents transient analysis using actual plant information. Values for trip setpoints, time delays and error allowances are also provided in Chapter 15. The results and conclusions presented there indicate that for all postulated transient conditions both primary and secondary system pressures remain within 110% of the respective design values. Therefore, the conclusions presented in Reference 2 are valid for Comanche Peak.

5.2.2.2 Design Evaluation

The relief capacities of the pressurizer and steam generator safety valves are determined from the postulated overpressure transient conditions in conjunction with the action of the Reactor Protection System. An evaluation of the functional design of the system and an analysis of the capability of the system to perform its function is presented in Reference [2]. The report describes in detail the types and number of pressure relief devices employed, relief device description, locations in the systems, reliability history, and the details of the methods used for relief device sizing based on typical worst condition. The description of the analytical model used in the analysis of the overpressure protection system and the basis for its validity is discussed in Reference [3].

A description of the pressurizer safety valves performance characteristics along with the design description of the incidents, assumptions made, method of analysis and conclusions are discussed in Chapter 15.

5.2.2.3 Piping and Instrumentation Diagrams

Overpressure protection for the RCS is provided by pressurizer safety valves shown in Figure 5.1-1, Sheet 2. These discharge to the pressurizer relief tank by a common header.

The main steam supply system safety valves are discussed in Section 10.3 and are shown on Figure 10.3-1, Sheet 1 of 2.

5.2.2.4 Equipment and Component Description

The operation, significant design parameters, number and types of operating cycles, and environmental qualification of the pressurizer safety valves are discussed in Section 5.4.13.

A discussion of the equipment and components of the main steam supply system overpressure protection is discussed in Section 10.3

5.2.2.5 Mounting of Pressure-Relief Devices

Westinghouse provides the architect engineer with installation guidelines and suggested physical layout. This information is transmitted to the architect engineer as part of a systems standard design criteria document. The architect engineer is required by Westinghouse to limit the piping reaction loads on the safety valves to acceptable values.

Westinghouse provides mounting brackets on the pressurizer which can be used to support the pressurizer safety valves. The architect engineer is responsible for the design and mounting of the supports of these valves. They are also responsible for determining reactions on the pressurizer mounting brackets.

Mounting of the components of the main steam supply system overpressure protection is discussed in Section 10.3

5.2.2.6 Applicable Codes and Classification

The requirements of ASME Code, Section III, paragraphs NB-7300 (Over-pressure Protection Report) and NC-7300 (Overpressure Protection Analysis), are followed and complied with for pressurized water reactor systems.

Piping, valves and associated equipment used for overpressure protection are classified in accordance with American Nuclear Society (ANS) N18.2, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants.” These safety class designations are delineated on Table 3.2-2 and shown on Figure 5.1-1.

For further information, refer to Section 3.9N.

5.2.2.7 Material Specifications

Refer to Section 5.2.3 for a description of material specifications.

5.2.2.8 Process Instrumentation

Each pressurizer safety valve discharge line incorporates a control board temperature indicator and alarm to notify the operator of steam discharge due to either leakage or actual valve operation. For a further discussion on process instrumentation associated with the system, refer to Chapter 7.

5.2.2.9 System Reliability

The reliability of the pressure relieving devices is discussed in Section 4 of Reference [2].

5.2.2.10 Testing and Inspection

Testing of the overpressure protection system is conducted in the following manner:

1. A test is performed to assure operability of system electronics in accordance with Technical Specification requirements.

2. A test for valve operability is conducted as specified in ASME Code Section XI.

3. Subsequent to system, valve or electronics maintenance, a test on that portion(s) of the system is performed prior to declaring the system operable.

Testing and inspection of the overpressure protection components are discussed in Section 5.4.13.4 and Chapter 14.

5.2.2.11 RCS Pressure Control During Low Temperature Operation

Administrative procedures are developed to aid the operator in controlling RCS pressure during low temperature operation. These include ensuring a path to a RHR suction relief valve is open whenever the RCS is water solid. However, to provide a back-up to the operator and to minimize the frequency of RCS overpressurization, an automatic system is provided to mitigate the pressure excursion to address the allowable pressure, obtained from the Pressure and Temperature Limits Report.

Analyses have shown that either one PORV or one RHR suction relief valve is sufficient to prevent violation of the RCS pressure limits as a result of anticipated mass and heat input transients.

However, redundant protection against such over-pressurization is provided through use of two PORV's or two RHR Suction Relief Valves, or a combination of a PORV and a RHR Suction Relief. The PORVs are automatically armed and activated to mitigate any potential pressure transients during low temperature water solid operation.

5.2.2.11.1 System Operation

Both pressurizer power operated relief valves are supplied with actuation logic to ensure that a redundant and independent RCS pressure control back-up feature is provided for the operator during low temperature operations. This system provides the capability for RCS inventory letdown, thereby maintaining RCS pressure within allowable limits. Refer to Sections 5.4.7, 5.4.10, 5.4.13, 7.7 and 9.3.4 for additional information on RCS pressure and inventory control during other modes of operation.

Each of the two PORV's is supplied with an independent, seismically designed supply of nitrogen which is sized to assure that no operator action is required to terminate the transient for 10 minutes. High pressure nitrogen will be regulated down to the required operating pressure for

the PORV actuators. Relief valves provide protection against over-pressurizing the actuators due to regulator failure.

The basic function of the system logic is to continuously monitor RCS temperature and pressure conditions whenever plant operation is at low temperatures. An auctioneered system temperature will be continuously converted to an allowable pressure and then compared to the actual RCS pressure. This system logic will first annunciate a main control board alarm whenever the measured pressure approaches a pre-determined amount of the allowable pressure thereby indicating a pressure transient is occurring. On a further increase in measured pressure, an actuation signal is transmitted to the power operated relief valves when required to mitigate pressure transient.

5.2.2.11.2 Evaluation of Low Temperature Overpressure Transients

Pressure Transient Analyses

ASME Section III, Appendix G, establishes guidelines and upper limits for RCS pressure, primarily for low temperature conditions (≤350°). The mitigation system discussed in this section satisfies these conditions, as discussed in the following paragraphs.

Transient analyses were performed to determine the maximum pressure for the postulated mass input and heat input events.

The mass input pressure transient which is most likely during the course of normal plant operation would involve letdown isolation with charging pumps delivering an input less than or equal to 120 gpm. However, the mass input analysis was performed assuming letdown isolation with two charging pumps operating in a configuration producing maximum delivery rates. This more unlikely and more severe configuration was chosen to provide additional system flexibility for pressure control.

The maximum setpoint overpressure achieved for two charging pump operation with letdown isolation will vary with valve setpoint pressure. For example, at low RCS temperatures with a setpoint pressure of 505 psig the peak overpressure for PORV discharge is calculated to be 565 psi. At an RCS temperature of 200° and a setpoint pressure of 640 psig, the water discharge peak overpressure would be 700 psig.

The heat input transient analysis is performed over the entire RCS shutdown temperature range. This analysis also assumes an inadvertent reactor coolant pump startup with a 50°F mismatch.

Both heat input and mass input analyses took into account the single failure criteria and therefore, only one power operated relief valve (PORV) was assumed to be available for pressure relief. The above events have been evaluated considering the allowable pressure/ temperature limits established in the Pressure and Temperature Limits Report. The evaluation of the transient results conclude that the allowable limits will not be exceeded and therefore will not constitute an impairment to vessel integrity and plant safety.

In addition, the probability of a loss of a complete DC bus concurrent with a low temperature overpressure event concurrent with a PORV failure was considered. In the CPNPP design, the failure of the Train A DC bus will cause the letdown valve and Train A RCS PORV to fail in the closed position, i.e., not being able to open on demand. However, the Train B PORV is not the

only remaining available means to mitigate on overpressurization event under these conditions. There are several methods by which the operator can be made aware of this scenario, including an alarm when the DC bus fails, an alarm before the pressure relief setpoint is reached, and panel indication of system pressure. The operator has several methods to mitigate the accident, including automatic or manual operation of the Train B PORV, manual operation of an RCS vent, stopping RCS heatup, stopping the centrifugal charging pumps, and increasing RCS reactor coolant pump seal return flow. The probability of an overpressurization event under these conditions is considered to be very small; when the alternative means of mitigation as described above are taken into account along with the very low probability, the CPNPP design is considered adequate.

5.2.2.11.3 Operating Basis Earthquake Evaluation

A fluid systems evaluation has been performed considering the potential for overpressure transients following an Operating Basis Earthquake (OBE). The most likely failure of the cold overpressure mitigation system during an OBE is the loss of plant nitrogen supply system. Therefore, this system employs seismically qualified nitrogen reservoirs which ensure that motive force to the PORVs will be maintained during an OBE.

The PORVs have been designed in accordance with the ASME code to provide the integrity required for the reactor coolant pressure boundary. The PORVs and associated valve operators have been analyzed for accident loads and for loads imposed by seismic events and have been shown to maintain their integrity. As a minimum, this means that pressure boundary joints remain leaktight. Yokes, frames and similar structures will not break, actuators will not freeze or bind, and the structural integrity of the valve internals will not be degraded. Should an OBE occur, the operability of the pressurizer PORVs can be easily checked by closing the block valves and testing the PORVs. If any problems are found, the operator would take additional precautionary measures during low temperature conditions to ensure that an overpressurization does not occur and that pressure excursions are quickly mitigated.

5.2.2.11.4 Administrative Procedures

Although the system described in Section 5.2.2.11.1 is installed to mitigate the pressure excursion to address the allowable pressure limits, administrative procedures are recommended for minimizing the potential for any transient that could actuate the overpressure relief system. The following discussion highlights these procedural controls, listed in hierarchy of their function in preventing RCS cold overpressurization transients.

Of primary importance is the basic method of operation of the plant. Normal plant operating procedures will maximize the use of a pressurizer cushion (steam/nitrogen bubble) during periods of low pressure, low temperature operation. This cushion will dampen the plants response to potential transient generating inputs, providing easier pressure control with slower response rates.

An adequate cushion substantially reduces the severity some potential pressure transients such as reactor coolant pump induced heat input and slows the rate or pressure rise for others. In conjunction with the previously discussed alarms, this provides reasonable assurance that most potential transients can be terminated by operator action before the overpressure relief system actuates.

However, for those modes of operation when water solid operation may still be possible, procedures will minimize the potential for developing an overpressurization transient. The following procedural controls will be effected:

1. Both residual heat removal inlet lines from the reactor coolant loops will not be isolated unless the charging pumps are stopped. This precaution is to assure there is a relief path from the reactor coolant loop to a residual heat removal suction line relief valve when the RCS is at low pressure (less than 500 psi) and is water solid.

2. When the plant is water solid and the reactor coolant pressure is being maintained by the low pressure letdown control valve, letdown flow will bypass the normal letdown orifices, and the valve in the bypass line will be in the full open position. During this mode of operation, all three letdown orifices will also remain open.

3. If all reactor coolant pumps (RCP) have stopped for more than 5 minutes during plant heatup, and the reactor coolant temperature is greater than the charging and seal injection water temperature, RCP restart will not be attempted unless a steam bubble is formed in the pressurizer. This precaution will minimize the pressure transient when the pump is started and the cold water previously injected by the charging pumps is circulated through the warmer reactor coolant components. The steam bubble will accommodate the resultant expansion as the cold water is rapidly warmed.

4. If all reactor coolant pumps are stopped and the RCS is being cooled down by the RHR heat exchangers, a non-uniform temperature distribution may occur in the reactor coolant loops. RCP restart will not be a attempted unless a steam bubble is formed in the pressurizer.

5. During plant cooldown, all steam generators are either connected to the header or isolated. Procedures controls will be established to assure a uniform RCS cooldown when the MSIVs are closed.

6. At least one reactor coolant pump will remain in service until the reactor coolant temperature is reduced to 160°F.

7. RCPs will not be started in a water solid RCS, if the temperature difference between the steam generator and the RCS is greater than 50°F.

These special precautions back-up the normal operational mode of maximizing periods of steam bubble operation so that cold overpressure transient prevention is continued during periods of transitional operations.

The configurations of ECCS testing and alignment will also minimize the potential for developing a cold overpressurization transient. During these limited periods of plant operation, the following procedural controls will be effected:

1. To preclude inadvertent emergency core cooling system (ECCS) actuation during heatup and cooldown, procedures will require blocking the low pressurizer pressure and low compensated steam line pressure, safety injection signal actuation logic below the P-11 interlock setpoint. Block features associated with pressurizer and steam line safety injection signals are discussed in Section 7.3.2.2.6.

2. During further cooldown, closure and power lockout of the accumulator isolation valves will be performed at RCS conditions less than 1000 psig and 350°F, and power lockout of charging pumps and safety injection pumps will be performed at RCS conditions less than 350°F as required by Technical Specifications. This provides additional back-up to step 1.) above.

3. The preferred procedure for periodic ECCS pump performance testing will be to test the pumps during normal power operation or at hot shutdown conditions. This precludes any potential for developing a cold overpressurization transient.

   When cold shutdown testing of the pumps is required, the test will be done by one of the following means, precluding overpressurization potential:

   a. With the reactor vessel head off, or

   b. With the reactor vessel head on and with the necessary ECCS pump discharge valve closure (either a closed isolation valve with power removed from the valve operator, or a manual isolation valve secured in the closed position) to isolate potential ECCS pump input. During such testing, which takes place during RHR system operation, the RHR suction relief valves provide some additional backup relief protection.

4. "S" signal circuitry testing, if done during cold shutdown, will also require RHRS alignment and non-operating ECCS pumps power lockout to preclude developing cold overpressurization transients.

The above procedural considerations covering normal operations with a steam bubble, transitional operations where potentially water solid, and specific testing operations provide in-depth cold overpressure preventions or reductions. These procedures thereby augment the installed automatic overpressure relief system.

5.2.3 REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

5.2.3.1 Material Specifications

Material specifications used for the principal pressure retaining applications in each component comprising the RCPB are listed in Table 5.2-2 for ASME Class 1 primary components and Table 5.2-3 for ASME Class 1 and 2 auxiliary components. Tables 5.2-2 and 5.2-3 for ASME Class 1 and 2 auxiliary components. Tables 5.2-2 and 5.2-3 include the unstabilized austenitic stainless steel material specifications used for the: 1) RCPB, 2) systems required for reactor shutdown, and 3) systems required for emergency core cooling.

The unstabilized austentic stainless steel material for the reactor vessel internals which are required for emergency core cooling for any mode of normal operation or under postulated accident conditions and for core structural load bearing members are listed in Table 5.2-4.

The materials are procured in accordance with the material specification requirements and include the special requirements of the ASME Code, Section III, plus addenda and code cases as are applicable and appropriate to meet Appendix B of 10CFR50.

In some cases, Table 5.2-3 may not be totally inclusive of the material specifications used in the listed applications. However, the listed specifications are representative of those materials utilized. All of the materials used are procured in accordance with ASME Code requirements.

The welding materials used for joining the ferritic base materials of the RCPB, conform to or are equivalent to ASME Material Specifications SFA 5.1, 5.2, 5.5, 5.17, 5.18 and 5.20. They are tested and qualified to the requirements of the ASME Code, Section III. In addition the ferritic materials of the reactor vessel beltline are restricted to the following maximum limits of copper, phosphorous and vanadium to reduce sensitivity to irradiation embrittlement in service:

Element	Base Metal(%)	As Deposited Weld Metal(%)
Copper	0.10 (ladle) 0.12 (check)	0.10
Phosphorous	0.012 (ladle) 0.017 (check)	0.015
Vanadium	0.05 (check)	0.05 (as residual)

The welding materials used for joining the austenitic stainless steel base materials of the RCPB conform to ASME Material Specifications SFA 5.4 and 5.9. They are tested and qualified according to the requirements of the ASME Code, Section III.

The welding materials used for joining nickel-chromium-iron alloy in similar base material combination and in dissimilar ferritic or austenitic base material combination conform to ASME Material Specifications SFA 5.11 and 5.14. They are tested and qualified to the requirements of the ASME Code, Section III.

5.2.3.2 Compatibility With Reactor Coolant

5.2.3.2.1 Chemistry of Reactor Coolant

The RCS chemistry specifications are given in Table 5.2-5.

The RCS water chemistry is selected to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications.

The Chemical and Volume Control System provides a means for adding chemicals to the RCS which control the pH and oxygen content of the coolant. The oxygen content and pH limits for power operations are shown in Table 5.2-5.

The pH control chemical employed is lithium-7 hydroxide. This chemical is chosen for its compatibility with the materials and water chemistry of borated water/stainless steel/zirconium/nconel systems. In addition, lithium is produced in solution from the neutron irradiation of the dissolved boron in the coolant. The lithium-7 hydroxide is introduced into the RCS via the charging flow. The solution is prepared in the laboratory and poured into the

chemical mixing tank. Reactor makeup water is then used to flush the solution to the suction header of the charging pumps. The concentration of lithium-7 hydroxide in the RCS is maintained in the range specified for pH control. If the concentration exceeds this range, the cation bed demineralizer is employed in the letdown line in series operation with the mixed bed demineralizer. Since the amount of lithium to be removed is small and its buildup can be readily calculated and determined by analysis, the flow through the cation bed demineralizer is not required to be full letdown flow.

Hydrazine is employed as an oxygen scavenging agent during reactor startup from cold condition or during reactor shutdown to a cold condition. The hydrazine solution is introduced into the RCS in the same manner as described above for the pH control agent.

Dissolved hydrogen is employed to control and scavenge oxygen produced due to radiolysis of water in the core region. Sufficient partial pressure of hydrogen is maintained in the volume control tank such that the specified equilibrium concentration of hydrogen is maintained in the reactor coolant. A self-contained pressure control valve maintains a minimum pressure in the vapor space of the volume control tank. This can be adjusted to provide the correct equilibrium hydrogen concentration.

5.2.3.2.2 Compatibility of Construction Materials With Reactor Coolant

All the ferritic low alloy and carbon steels which are used in principal pressure retaining applications are provided with corrosion resistant cladding on all surfaces that are exposed to the reactor coolant. This cladding material has a chemical analysis which is at least equivalent to the corrosion resistance of Types 304 and 316 austenitic stainless steel alloys or nickel-chomium-iron alloy, martensitic stainless steel and precipitation hardened stainless steel. The cladding on ferritic type base materials receives a post- weld heat treatment.

Ferritic low alloy and carbon steel nozzles are safe ended with either stainless steel wrought materials, stainless steel weld metal analysis A-7, or nickel-chromium-iron alloy weld metal F-Number 43. The latter buttering material requires further safe ending with austenitic stainless steel base material after completion of the post-weld heat treatment when the nozzle is larger than a 4 inch nominal inside diameter and/or the wall thickness is greater than 0.531 inches.

All of the austenitic stainless steel and nickel-chromium-iron alloy base materials with primary pressure retaining applications are used in the solution anneal heat treat condition. These heat treatments are as required by the materials specifications.

During subsequent fabrication, these materials are not heated above 800°F other than locally by welding operations. The solution annealed surge line material is subsequently formed by hot bending followed by a resolution annealing heat treatment.

Components with stainless steel sensitized in the manner expected during component fabrication and installation will operate satisfactorily under normal plant chemistry conditions in pressurized water reactor systems because chlorides, fluorides and oxygen are controlled to very low levels.

5.2.3.2.3 Compatibility With External Insulation and Environmental Atmosphere

In general, all of the materials listed in Tables 5.2-2 and 5.2-3 which are used in principal pressure retaining applications and which are subject to elevated temperature during system operation are in contact with thermal insulation that covers their outer surfaces.

The thermal insulation used on the RCPB is either reflective stainless steel type or to be made of compounded materials which yield low leachable chloride and/or fluoride concentrations. The compounded materials in the form of blocks, boards, cloths, tapes, adhesives, cements, etc., are silicated to provide protection of austenitic stainless steels against stress corrosion which may result from accidental wetting of the insulation by spillage, minor leakage or other contamination from the environmental atmosphere. Appendix 1A.(N) includes a discussion which indicates the degree of conformance with Regulatory Guide 1.36, “Nonmetallic Thermal Insulation for Austenitic Stainless Steel.”

In the event of coolant leakage, the ferritic materials will show increased general corrosion rates. Where minor leakage is anticipated from service experience, such as valve packing, pump seals, etc., only materials which are compatible with the coolant are used. These are as shown in Tables 5.2-2 and 5.2-3. Ferritic materials exposed to coolant leakage can be readily observed as part of the inservice visual and/or nondestructive inspection program to assure the integrity of the component for subsequent service.

5.2.3.3 Fabrication and Processing of Ferritic Materials

5.2.3.3.1 Fracture Toughness

The fracture toughness properties of the RCPB components meet the requirements of the ASME Code, Section III, paragraphs NB-2300, NC- 2300 and ND-2300 as appropriate.

Limiting steam generator and pressurizer RT_{NDT} temperatures are guaranteed at 60°F for the base materials and the weldments. These materials will meet the 50 ft-lb absorbed energy and 35 mils lateral expansion requirements of the ASME Code, Section III at 120°F. The actual results of these tests are provided in the ASME material data reports which are supplied for each component and are submitted to Texas Utilities at the time of shipment of the component. Fracture toughness tests for RCPB components are performed in accordance with written procedures, by operators qualified by training and experience.

Calibration of temperature instruments and charpy impact test machines are performed to meet the requirements of the ASME Code, Section III, paragraph NB-2360.

Westinghouse has conducted a test program to determine the fracture toughness of low alloy ferritic materials with specified minimum yield strengths greater than 50,000 pounds per square inch (psi) to demonstrate compliance with Appendix G of the ASME Code, Section III. The results of this program are discussed in reference [7].

SA-508 Class 2a and SA-533 Grade A Class 2 material was used in the fabrication of Comanche Peak Units 1 and 2 pressurizers. The conclusions of Westinghouse topical report WCAP-9292 [7] are applicable to the Comanche Peak Units.

5.2.3.3.2 Control of Welding

All welding is conducted utilizing procedures qualified according to the rules of Sections III and IX of the ASME Code. Control of welding variables, as well as examination and testing, during procedures qualification and production welding is performed in accordance with ASME Code requirements.

Appendix 1A(N) includes discussions which indicate the degree of conformance of the ferritic materials components of the RCPB with Regulatory Guides 1.34, “Control of Electroslage Properties,” 1.43, “Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components,” 1.50, “Control of Preheat Temperature for Welding of Low-Alloy Steel,” 1.66, “Nondestructive Examination of Tubular Products,” and 1.71, “Welder Qualification for Areas of Limited Accessibility.”

5.2.3.4 Fabrication and Processing of Austenitic Stainless Steel

Sections 5.2.3.4.1 through 5.2.3.4.5 address Regulatory Guide 1.44, “Control of the Use of Sensitized Stainless Steel,” and present the methods and controls utilized by Westinghouse to avoid sensitization and prevent intergranular attach of austenitic stainless steel components. Also, Appendix 1A(N) includes a discussion which indicates the degree of conformance with Regulatory Guide 1.44.

5.2.3.4.1 Cleaning and Contamination Protection Procedures

It is required that all austenitic stainless materials used in the fabrication, installation and testing of nuclear steam supply components and systems be handled, protected, stored and cleaned according to recognized and accepted methods which are designed to minimize contamination which could lead to stress corrosion cracking. The rules covering these controls are stipulated in Westinghouse process specifications. As applicable these process specifications supplement the equipment specifications and purchase order requirements of every individual austenitic stainless steel component or system which Westinghouse procures for the CPNPP NSSS, regardless of the ASME Code classification.

The process specifications which define these requirements and which are in compliance with ANSI N-45 committee specifications are as follows:

Process Specification Number	
82560HM	Requirements for Pressure Sensitive Tapes for use on Austenitic Stainless Steels.
83336KA	Requirements for Thermal Insulation Used on Austenitic Stainless Steel Piping and Equipment.
83860LA	Requirements for Marking of Reactor Plant Components and Piping.

84350HA	Site Receiving Inspection and Storage Requirements for Systems, Material and Equipment.
84351NL	Determination of Surface Chloride and Fluoride on Austenitic Stainless Steel Materials.
85310QA	Packaging and Preparing Nuclear Components for Shipment and Storage.
292722	Cleaning and Packaging Requirements of Equipment for Use in the NSSS.
597756	Pressurized Water Reactor Auxiliary Tanks Cleaning Procedures.
597760	Cleanliness Requirements During Storage Construction, Erection and Startup Activities of Nuclear Power Systems.

Appendix 1A(N) includes a discussion which indicates the degree of conformance of the austenitic stainless steel components of the RCPB with Regulatory Guide 1.37, “Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants”.

5.2.3.4.2 Solution Heat Treatment Requirements

The austenitic stainless steels listed in Tables 5.2-2, 5.2-3 and 5.2- 4 are utilized in the final heat treated condition required by the respective ASME Code, Section II materials specification for the particular type or grade of alloy.

5.2.3.4.3 Material Inspection Program

The Westinghouse practice is that austenitic stainless steel materials of product forms with simple shapes need not be corrosion tested provided that the solution heat treatment is followed by water quenching. Simple shapes are defined as all plates, sheets, bars, pipe and tubes, as well as forgings, fittings, and other shaped products which do not have inaccessible cavities or chambers that would preclude rapid cooling when water quenched. When testing is required, the tests are performed in accordance with ASTM-A-262-70, Practices A or E, as amended by Westinghouse Process Specification 84201 MW.

5.2.3.4.4 Prevention of Intergranular Attack of Unstabilized Austenitic Stainless Steels

Unstabilized austenitic stainless steels are subject to intergranular attack (IGA) provided that three conditions are present simultaneously. These are:

1. An aggressive environment, e.g., an acidic aqueous medium containing chlorides or oxygen.

2. A sensitized steel.

3. A high temperature.

If any one of the three conditions described above is not present, intergranular attack will not occur. Since high temperatures cannot be avoided in all components in the NSSS, Westinghouse relies on the elimination of conditions 1 and 2 to prevent intergranular attack on wrought stainless steel components.

The water chemistry in the RCS of a Westinghouse pressurized water reactor is rigorously controlled to prevent the intrusion of aggressive species. In particular, the maximum permissible oxygen and chloride concentrations are 0.10 and 0.15 parts per million (ppm), respectively. Reference [4] describes the precautions taken to prevent the intrusion of chlorides into the system during fabrication, shipping, and storage. The use of hydrogen over pressure precludes the presence of oxygen during operation. The effectiveness of these controls has been demonstrated by both laboratory tests and operating experience. The long time exposure of severely sensitized stainless in early plants to pressurized water reactor coolant environments has not resulted in any sign of intergranular attack. Reference [4] describes the laboratory experimental findings and the Westinghouse operating experience. The additional years of operations since the issuing of Reference [4] have provided further confirmation of the earlier conclusions. Severely sensitized stainless steels do not undergo any intergranular attack in Westinghouse pressurized water reactor coolant environments.

In spite of the fact there never has been any evidence that pressurized water reactor coolant water attacks sensitized stainless steels, Westinghouse considers it good metallurgical practice to avoid the use of sensitized stainless steels in the NSSS components. Accordingly, measures are taken to prohibit the purchase of sensitized stainless steels and to prevent sensitization during component fabrication. Wrought austenitic stainless steel stock used for components that are part of: 1) the RCPB, 2) systems required for reactor shutdown, 3) systems required for emergency core cooling, and 4) reactor vessel internals that are relied upon to permit adequate core cooling for normal operation or under postulated accident conditions is utilized in one of the following conditions:

1. Solution annealed and water quenched.

2. Solution annealed and cooled through the sensitization temperature range within less than approximately 5 minutes.

It is generally accepted that these practices will prevent sensitization. Westinghouse has verified this by performing corrosion tests (ASTM-393) on as-received wrought material. Westinghouse recognizes that the heat affected zones of welded component must, of necessity, be heated into the sensitization temperature range, 800 to 1500°F. However, severe sensitization, i.e., continuous grain boundary precipitates of chromium carbide, with adjacent chromium depletion, can still be avoided by control of welding parameters and welding processes. The heat input[a] and associated cooling rate through the carbide precipitation range are of primary importance. Westinghouse has demonstrated this by corrosion testing a number of weldments.

Of 25 production and qualification weldments tested, representing all major welding processes, and a variety of components, and incorporating base metal thicknesses from 0.10 to 4.0 inches, only portions of two were severely sensitized. Of these, one involved a heat input of 120,000 joules, and other involved a heavy socket weld in relatively thin walled material. In both cases, sensitization was caused primarily by high heat inputs relative to the section thickness. However, in only the socket weld did the sensitized condition exist at the surface, where the material is

exposed to the environment. The component has been redesigned and a material change has been made to eliminate this condition.

Westinghouse controls the heat input in all austenitic pressure boundary weldments by:

1. Prohibiting the use of block welding.

2. Limiting the maximum interpass temperature to 350°F.

3. Exercising approval rights on all welding procedures.

To further assure that these controls are effective in preventing sensitization, Westinghouse will, if necessary, conduct additional intergranular corrosion tests of qualification mock-ups of primary pressure boundary and core internal component welds, including the following:

1. Reactor vessel safe ends.

2. Pressurizer safe ends.

3. Surge line and reactor coolant pump nozzles.

4. Control rod drive mechanisms head adaptors.

5. Control rod drive mechanisms seal welds (Unit 2 only).

6. Control rod extensions.

7. Lower instrumentation penetration tubes.

To summarize, Westinghouse has a four point program designed to prevent intergranular attack of austenitic stainless steel components.

1. Control of primary water chemistry to ensure a benign environment.

2. Utilization of materials in the final heat treated condition and the prohibition of subsequent heat treatments in the 800 and 1500°F temperature range.

3. Control of welding processes and procedures to avoid heat affected zone sensitization.

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a. Heat input is calculated according to the formula:

Where $H = \frac{(E)(I)(60)}{S}$

H = joules/in
E = volts
I = amperes
S = travel speed (in/min)

4. Confirmation that the welding procedures used for the manufacture of components in the primary pressure boundary and of reactor internals do not result in the sensitization of heat affected zones.

Both operating experience and laboratory experiments in primary water have conclusively demonstrated that this program is 100 percent effective in preventing intergranular attack in Westinghouse NSSS's utilizing unstabilized austenitic stainless steel.

5.2.3.4.5 Retesting Unstabilized Austenitic Stainless Steels Exposed to Sensitization Temperatures

It is not normal Westinghouse practice to expose unstabilized austenitic stainless steels to the sensitization range of 800 to 1500°F during fabrication into components. If, during the course of fabrication, the steel is inadvertently exposed to the sensitization temperature range, 800 to 1500°F, the material may be tested in accordance with ASME-A-393 or A-262 as amended by Westinghouse Process Specification 84201 MW to verify that it is not susceptible to intergranular attack, except that testing is not required for:

1. Cast metal or weld metal with a ferite content of 5 percent or more.

2. Material with a carbon content of 0.03 percent or less that is subjected to temperatures in the range of 800 to 1500°F for less than 1 hour.

3. Material exposed to special processing provided the processing is properly controlled to develop a uniform product and provided that adequate documentation exists of service experience and/or test data to demonstrate that the processing will not result in increased susceptibility to intergranular stress corrosion.

If it is not verified that such material is not susceptible to intergranular attack, the material will be resolution annealed and water quenched or rejected.

5.2.3.4.6 Control of Welding

The following paragraphs address Regulatory Guide 1.31, "Control of Stainless Steel Welding," and present the methods used, and the verification of these methods, for austenitic stainless steel welding.

The welding of austenitic stainless steel is controlled to mitigate the occurrence of microfissuring or hot cracking in the weld. Although published data and experience have not confirmed that fissuring is detrimental to the quality of the weld, it is recognized that such fissuring is undesirable in a general sense. Also, it has been well documented in the technical literature that the presence of delta ferrite is one of the mechanisms for reducing the susceptibility of stainless steel welds to hot cracking. However, there is insufficient data to specify a minimum delta ferrite level below which the material will be prone to hot cracking. It is assumed that such a minimum lies somewhere between 0 and 3 percent delta ferrite.

The scope of these controls discussed herein encompasses welding processes used to join stainless steel parts in components designed, fabricated or stamped in accordance with ASME Code, Section III, Class 1 and 2, and core support components. Delta ferrite control is appropriate for the above welding requirements except where no filler metal is used or for other

reasons such control is not applicable. These exceptions include electron beam welding, autogenous gas shielded tungsten arc welding, explosive welding, and welding using fully austenitic welding materials.

The fabrication and installation specifications require welding procedure and welder qualification in accordance with the ASME Code, Section III, and include welding materials that are used for welding qualification testing and for production processing. Specifically, the undiluted weld deposits of the "starting" welding materials are required to contain a minimum of 5 percent delta ferrite[b] as determined by chemical analysis and calculation using the appropriate weld metal constitution diagrams in the ASME Code, Section III. When new welding procedure qualification tests are evaluated for these applications, including repair welding of raw materials, they are performed in accordance with the requirements of Sections III and IX of the ASME Code.

The results of all the destructive and nondestructive tests are reported in the procedure qualification record in addition to the information required by the ASME Code, Section III.

The "starting" welding materials used for fabrication and installation welds of austenitic stainless steel materials and components meet the requirements of the ASME Code, Section III. The austenitic stainless steel welding material conforms to ASME weld metal analysis A-7 (designated A8 in the 1974 Edition of the ASME B&PV Code), Type 308 for all applications except Type 308L weld metal analysis may be substituted for consumable inserts when used for weld root closures. Bare weld filler metal, including consumable inserts, used in inert gas welding processes conform to ASME SFA-5.9, and are procured to contain not less than 5 percent delta ferrite according to the ASME Code, Section III. Weld filler materials used in flux shielded welding processes conform to ASME SFA-5.4 or SFA-5.9 and are procured in a wire-flux combination to be capable of providing not less than 5 percent delta ferrite in the deposit according to the ASME Code, Section III. Welding materials are tested using the welding energy inputs to be employed in production welding.

Combinations of approved heat and lots of "starting" welding materials are used for all welding processes. The welding quality assurance program include identification and control of welding material by lots and heats as appropriate. All of the weld processing is monitored according to approved inspection programs which include review of "starting" materials, qualification records and welding parameters. Welding systems are also subject to quality assurance audit including calibration of gages and instruments: identification of "starting" and completed materials; welder and procedure qualifications; availability and use of approved welding and heat treating procedures; and documentary evidence of compliance with materials, welding parameters and inspection requirements. Fabrication and installation welds are inspected using nondestructive examination methods according to the ASME Code, Section III rules.

To assure the reliability of these controls, Westinghouse has completed a delta ferrite verification program, described in Reference [5] which has been approved as a valid approach to verify the Westinghouse hypothesis and is considered an acceptable alternative for conformance with the NRC interim position on Regulatory Guide 1.31. The NRC acceptance letter and topical report evaluation were received on December 30, 1974. The program results, which do support the hypothesis presented in Reference [5], are summarized in Reference [6].

b. The equivalent ferrite number may be substituted for percent delta ferrite.

Appendix 1A(N) includes discussions which indicate the degree of conformance of the austenitic stainless steel components of the RCPB with Regulatory Guides 1.34, “Control of Electroslag Properties,” 1.66, “Nondestructive Examination of Tubular Products,” and 1.71, “Welder Qualification for Areas of Limited Accessibility.”

5.2.4 INSERVICE INSPECTION AND TESTING OF THE REACTOR COOLANT PRESSURE BOUNDARY

This section describes the Inservice Inspection Program which will ensure the integrity of the reactor coolant pressure boundary. The Inservice Inspection Program for Class 1 systems and component supports is written in accordance with subsections IWB and IWF of Section XI, ASME Boiler & Pressure Vessel Code (Edition and Addenda as required by 10CFR50.55a).

The Inservice and Preservice Inspection Programs shall be in accordance with the guidelines of Subsections IWA and IWB of Section XI, ASME Boiler and Pressure Vessel Code (Edition and Addenda as required by 10CFR50.55a). During the preservice inspection, Class 1 systems were inspected to the 1980 Edition for Unit 1 and to the 1983 Edition with Code Case N-408 for Unit 2 except the reactor pressure vessel was for 1980 Edition. Details of the preservice inspection, including relief requests, are included in the Preservice Inspection Plan for each unit.

5.2.4.1 System Boundary Subject To Inspection

The system boundary subject to inspection includes all Safety Class 1 pressure-retaining components (and their integral attachments) as defined in IWB-1200.

5.2.4.2 Accessibility

The reactor coolant pressure boundary is designed to the extent practical so that provisions for access, as required by Subarticle IWA-1500 of ASME Section XI, can be followed.

The components, the equipment layout, and the support structures of the Reactor Coolant System have been designed to the extent practical to permit access for inspection purposes.

Reactor Vessel

Specific provision to be made for inspection access in the design of the reactor vessel, system layout and other major primary coolant components will be as follows:

1. All reactor internals will be completely removable. The tools and storage space required to permit reactor internals removal for these inspections will be provided.

2. The reactor vessel shell in the core area will be designed with a clean, uncluttered cylindrical inside surface to permit future positioning of test equipment without obstruction.

3. The reactor vessel cladding will be improved in finish by the vessel manufacturer by grinding to the extent necessary to permit meaningful examination of the vessel welds and adjacent base metal in accordance with the Code.

4. The cladding to base metal interface will be ultrasonically examined by the vessel manufacturer to assure satisfactory bonding to allow the volumetric inspection of the vessel welds and base metal from the vessel inside surface.

5. The reactor closure head will be stored in a dry condition on the operating deck during refueling, allowing direct access for inspection.

6. The insulation on the vessel closure and lower heads will be removable, allowing access for nondestructive examination of head welds.

7. All reactor vessel studs, nuts, and washers may be removed to dry storage during refueling, allowing inspection in parallel with refueling operations.

8. Access holes will be provided in the core barrel flange allowing access for the remote visual examination of the clad surface of the vessel without removal of the lower internals assembly.

9. Removable plugs will be provided in the primary shield providing access for the surface and volumetric examination of the primary nozzle O.D. safe-end-welds.

The use of conventional non-destructive, volumetric test techniques can be applied to the inspection of all primary loop components except for the reactor vessel. The reactor vessel presents special problems because of the radiation levels and remote underwater accessibility to this component.

Pressurizer

A manway is provided in the pressurizer top head to allow access for internal inspection.

Steam Generator

Manways will be provided in the steam generator channel head to provide access for internal inspection.

Reactor Coolant Pumps

The external surfaces of the pump casings are accessible for inspection. The internal surface of the pump is available for inspection by removing the pump motor and pump internals.

Piping

The reactor coolant piping, fittings, and attachments to the piping external to the primary shield are accessible for external surface and volumetric inspections in areas where inspection is required.

Insulation

The insulation covering all component and piping welds and adjacent base metal is designed for ease of removal and replacement in areas where external inspection will be planned.

Components' Location Relative To Structure and Adjacent Components

The primary loop compartments are designed to allow personnel entry during refueling operations in order to permit direct inspections access to the external portion of piping and components. Provisions for adequate distance between component areas requiring inspection and adjacent components and structures have been factored into the design and layout of components.

5.2.4.3 Examination Techniques and Procedures

Visual, surface, and volumetric examination techniques and procedures, including any special technique and procedure, are in accordance with the requirements of ASME Section XI.

5.2.4.4 Inspection Intervals

The required examinations and pressure tests will be completed during each 10-year interval of service in accordance with ASME Section XI.

5.2.4.5 Examination Categories and Requirements

The categories and requirements appropriate for each examination area follow the categories and requirements specified in ASME Section XI. An inservice inspection program which discusses the examination categories will be provided.

5.2.4.6 Evaluation of Examination Results

Evaluation of examination results for Class 1 components will be conducted in accordance with ASME Section XI.

Unacceptable indications will be repaired in accordance with the requirements of ASME Section XI.

5.2.4.7 System Leakage Tests

The System Leakage tests for the reactor pressure vessel and reactor coolant pressure boundary will be conducted in accordance with the requirements of ASME Section XI.

5.2.5 DETECTION OF LEAKAGE THROUGH REACTOR COOLANT PRESSURE BOUNDARY

The leakage-detection systems are intended to sense leakage from the reactor coolant and auxiliary systems into the Containment and to provide the means to locate such leakage.

The safety significance of leaks through the reactor coolant pressure boundary (RCPB) can vary widely depending on the source of the leak as well as the leakage rate and duration. Therefore, the detection and monitoring of reactor coolant leakage into the Containment is necessary.

The leakage-detection systems provide information which permits the plant operators to take immediate corrective action should a leak be evaluated as detrimental to the safety of the plant.

Leakage-detection system design objectives are in accordance with the requirements of 10 CFR Part 50, GDC 30, and NRC Regulatory Guide 1.45.

5.2.5.1 Leakage Classification and Limits

RCPB leakage is classified as identified or unidentified and methods for physically separating the leakage into these classifications are provided to supply prompt and quantitative information about the leakage to the plant operators. Definitions of identified and unidentified leakage are as follows:

5.2.5.1.1 Identified Leakage

Identified leakage is reactor coolant leakage into the containment area (i.e. into a closed system or containment atmosphere) that is specifically located, can be detected, collected and to the extent practical, isolated from the containment atmosphere so as not to mask any potentially serious leak should it occur.

Identified leakage is comprised of:

1. Leakage, from reactor head flange leak-offs and valve packing leak-offs, that is captured and conducted to the reactor coolant drain tank (RCDT). FSAR Figure 11.2-2 shows the Reactor Coolant Drain Subsystem. All reactor coolant pressure boundary valves that use the compressed packing method of sealing the working fluid are equipped with piped leak-off connections and the potential leaks are classified as identified. Since the leakage detection system is closed, it is essentially isolated from the Containment atmosphere and cannot mask any potentially serious leakage to the atmosphere from unidentified sources including a flaw in the RCPB.

2. Reactor coolant leakage through steam generators to the secondary system.

3. Leakage through the closed pressurizer safety and relief valves.

4. Leakage of the seal water through the reactor coolant pumps seal number 2 directed to the Reactor Coolant Drain Tank (reactor coolant pump seal leak-off number 2).

5. Leakage of the seal water through the reactor coolant pumps seal number 3 directed to the Containment Sump (reactor coolant pump seal leak-off number 3).

6. Leakage of the reactor coolant to the Component Cooling Water System (CCWS) resulting from leakage from the Reactor Coolant Pumps thermal barrier.

7. Intersystem leakage through Reactor Coolant System Pressure Isolation Valves.

All identified leakage (except primary-to-secondary leakage, intersystem leakage, RC pump seal No. 3 leakage and closed pressurizer safety and relief valves leakage) is collected in Reactor Coolant Drain Tank.

The only circulating pumps located inside the Containment Building that are operational during normal plant operation are the reactor coolant drain tank pumps and the containment floor drain sump pumps (not considering the reactor coolant pumps).

The reactor coolant drain tank pumps are of “canned” type. The configuration of the pump shaft seal system is of a completely closed system with no communication with the containment atmosphere.

The shaft seal leakage of the containment floor drain sump pumps are returned to the floor sump and are not considered as system outleakage.

Based on the above consideration leakage through the pump shaft seals is not entering a closed system or containment atmosphere and as such considered as completely leaktight.

5.2.5.1.2 Unidentified Leakage

Unidentified leakage is all leakage which is not identified leakage or controlled leakage. It is impractical to completely eliminate unidentified leakage, but efforts are made to reduce this leakage to a small background flow rate permitting the leakage detection systems to detect positively and rapidly any small increase in unidentified leakage flow rate.

5.2.5.1.3 Controlled Leakage

Controlled leakage is the seal water flow supplied to the reactor coolant pump seal number 1 (approximately 8-gpm per pump). The reactor coolant pump seal subsystem is discussed in Section 9.3.

5.2.5.1.4 Limits for Reactor Coolant Leakage

Leakage through the RCPB is limited to the following:

1. Identified leakage

    a. 150 gpd through any one steam generator

    b. 10-gpm total leakage (Items 1, 2, 3, 4, 5, 6, and 7 in Section 5.2.5.1.1)

2. Unidentified leakage

    a. 1-gpm limit.

5.2.5.1.5 Maximum Allowable Identified Leakage

As stated in Technical Specifications, Limiting Conditions for Operation, operation of the reactor is permitted with a total primary system identified leakage not exceeding flow rates as specified in Section 5.2.5.1.4.

For a maximum allowable capacity of the reactor coolant makeup system of 120-gpm, the ratio of the maximum allowable identified leakage to the makeup rate is 0.083.

For a normal capacity of the containment water removal system (sump pump) of 80-gpm, the ratio of the maximum allowable identified leakage to this normal capacity is 0.125.

5.2.5.1.6 Maximum Allowable Unidentified Leakage

Selection of 1.0-gpm as the maximum permissible unidentified leakage is based on the leakage behavior of cracks in piping under pressure as described in WCAP-7503 and discussed in the following paragraphs.

The lengths of through-wall cracks that are calculated to leak 0.5-gpm in 2-in. lines, 1-gpm in 3-in. lines and 2 gpm in 4 in. lines and larger are given in WCAP-7503 and are defined as detectable leakage crack lengths. This study also gives curves for detectable leakage crack length versus detectable leak rate for longitudinal and circumferential through-wall cracks.

In addition, this study gives the critical crack length which leads to pipe failure for both longitudinal and circumferential cracks. In all cases, the detectable leakage crack length is less than the critical crack length. The study shows the margins of safety and the number of years for a detectable leakage crack to grow to a critical crack size. If a leak is detected from a detectable leakage crack, there is sufficient time to shut down the plant and make all necessary repairs.

Although the 1-gpm maximum permissible unidentified leakage rate is larger than the 0.5-gpm leakage rate analyzed for cracks in 2-in lines, core cooling analyses have shown that for small breaks, i.e., breaks up to the equivalent of the cross-sectional area of 4-in- diameter lines, no reactor fuel-cladding damage is expected. Thus, the selection of 1-gpm maximum permissible unidentified leakage rate is a conservative choice.

5.2.5.2 Leakage Detection Methods

5.2.5.2.1 Identified Leakage

In general, identified leakage that is conducted to the Reactor Coolant Drain Tank and to the pressurizer relief tank is measured by means of a level change in the respective tank. Leakage into the RCDT may also be measured by a flow totalizer on the discharge of the RCDT level control valve. Identified leakage conducted to the Containment Sumps is measured by means of a flow totalizer in the Containment Sump Pumps discharge header (outside the Containment).

1. Steam Generator primary-to-secondary leakage is detected by the Steam Generator Blowdown Process Sample (SGBPS) Monitor (see Section 11.5.2.7.1), the Steam Generator Leak Rate (SGLRM) Monitors (see Section 11.5.2.6.13), and the Condenser Off-Gas Monitor (see Section 11.5.2.6.5).

2. Reactor head flange leak-off system

   The seal for the reactor vessel head is formed by two concentric o-rings with two intermediate leak-off lines. If leakage past the innermost o-ring occurs, it is detected by a surface mounted temperature detector located on the common leak-off line.

3. Pressurizer safety and relief valves

   Leakage from the closed pressurizer safety and relief valves is detected by a surface mounted temperature detector located on each safety valve discharge pipe on the common discharge header of the pressurizer relief valves.

4. Reactor Coolant Drain Tank

Leakage from valve stem packing leak-offs and from the RCS pump seal leak-offs to the Reactor Coolant Drain Tank is measured by means of a flow totalizer downstream of the level control valve or level change in the RCDT.

Monitoring of total leakage is done by observations of fluctuation of RCDT levels coupled with evaluation of operational occurrences. If a leakage rate that requires action is reached, the leaking component will be identified by entering the containment for inspection and valve packing leaks will be identified by taking piping surface temperature readings of the leak-off piping.

5. Leakage to the Component Cooling Water System

Any leakage of the reactor coolant to the Component Cooling Water System (CCWS) is detected by radiation monitors in the CCWS (see Section 11.5.2.7.6). Also, leakage into the CCWS can be detected as an increase in the level of the CCWS surge tank.

6. Pressure Isolation Valve Leakage

An SI injection header alternate relief path has been provided on Unit 2 (only) which may be used to manually bypass the injection header relief valves. This path includes the SI System Header Pressure Isolation Valve Leakage Monitoring System (Unit 2 only) which may be used to measure the RCS pressure isolation valve leakage. See Section 6.3.5.3.9 for more details.

5.2.5.2.2 Unidentified Leakage

Primary detection of unidentified leakage to the Containment atmosphere is provided by air particulate monitors, containment sump flow monitors and condensate flow rate measuring system. In addition, containment dewpoint, indication of gross leakage and liquid inventory and radioactive gas monitor are other indications available to the operator for determination of unidentified leakage.

In normal operation, the primary monitors show a background level which is indicative of the normal magnitude of unidentified leakage inside the Containment. Variations in airborne reactor coolant corrosion products or condensate flow rate above the normal level signifies an increase in unidentified leakage rates and signal to the plant operators that corrective action may be required. Similarly, increases in Containment sump flow and radioactive gaseous concentration in the containment atmosphere signifies an increase in unidentified leakage.

A description of these primary unidentified leakage monitors is provided below along with a description of other leakage indications available to the plant operator.

1. Containment Air Particulate Monitor

Air particulate monitors take continuous air samples from the containment atmosphere and measure the particulate activity collected on a filter paper system. After passing through an iodine and noble gas monitor downstream of the particulate monitor, the air returns to the Containment. (See Section 11.5.2.6.2)

The sensitivity of the Containment air particulate monitor to an increase in reactor coolant leak rate is dependent upon the magnitude of the normal baseline leakage into the Containment. Sensitivity is greatest where baseline leakage is lowest.

2. Radioactive Gas Monitor

The radioactive gas monitor indicates the presence of containment gaseous activity originating from fuel-cladding defects. It measures the gaseous beta radioactivity by continuously sampling the containment atmosphere. (See Section 11.5.2.6.2) The radioactive gas monitor is less sensitive to an increase in reactor coolant leak rate than the containment particulate monitor.

3. Containment Sump Flow Monitoring

After collection in containment sump 1, containment sump 2, or the reactor cavity sump, leakage is pumped via a common header to floor drain tank 1 or to the waste hold-up tank. In this common discharge header is a flow totalizer/indicator that measures flow and facilitates the recording of this total flow in the control room (see Figures 9.3-5 sh 1 and 2).

The sumps also have several other features as follows:

a. Any one of the 6 pumps in these 3 sumps starting causes the “ANY CONT SUMP PUMP RUN” audible/visual alarm to actuate in the control room.

b. Each of the 3 sumps has a separate high level audible/visual alarm in the control room.

c. Sumps 1 and 2 have an additional level switch arranged with a time delay and the appropriate logic so that an increase by 1 gpm or greater flow into the sump will actuate a “CONT SUMP FILL RATE INCREASE” audible/visual alarm in the control room.

The sump discharge line may be sampled from outside of the Containment to provide additional aid in identifying the leakage source.

4. Specific Humidity Monitors

Specific humidity monitors are sensitive to vapor originating from the reactor coolant, steam, feedwater, and auxiliary systems in the Containment. Therefore, these monitors provide a means of detecting unidentified leakage from both radioactive and non-radioactive sources. Humidity detection is accomplished either by measuring the condensate from the Containment air cooling coils or by monitoring the dewpoint temperature in the Containment. These methods are described as follows:

a. Condensate Flow Rate Measurement

Humidity detection is accomplished by measuring the condensate flow rate from the Containment cooling coils. The containment specific humidity increases proportionately with time and leakage until the dewpoint is reached at the

Containment recirculation unit cooling coils. If the specific humidity increases above this point, the heat removal needed to cool the air-steam mixture to its dewpoint temperature increases above this point.

Therefore, since the cooling coils are designed to remove heat at a constant rate, an increase in specific humidity results in increased condensate flow. The condensate measuring system consists of a vertical standpipe with an internal self-siphoning device which empties the condensate in the standpipe to the sump when the standpipe is nearly full. The condensate measuring system permits measurement of the condensate flow rate from each Containment recirculation unit by means of a derivative unit which measures the rate of change in the standpipe level. Should the leakage inside the Containment increase, the condensate flow also increases, thereby increasing the rate of change of the standpipe level. The rate of level change in the standpipe is continuously recorded on strip chart recorders in the Control Room. An alarm for high rate of level change is provided to warn Control Room personnel of an increase in the condensate flow rate. An alarm is also provided if condensate flow is greater than the amount of flow that the siphon can discharge to the sump. Through accurate measurements of condensate flow, a reliable estimate of the total leakage rate to the Containment can be made. The condensate flow measuring system is shown in Figure 9.3-5.

b. Containment Dewpoint Monitors

The Containment humidity sensing system consists of dewpoint sensors, signal conditioning units, cabling, indicators, and plant process computer inputs, all packaged in a system capable of the continuous, unattended, automatic operation for remote monitoring of the dewpoint of the Containment atmosphere. Dewpoint sensors are strategically located in five representative areas of the Containment and are capable of detecting and reading out a change of 1ºF in dewpoint. The signal conditioning units provide a linear output signal for transmission to a Control Room board-mounted analog indicator.

5. Containment Temperature Monitors

An increase in Containment temperature can indicate a leak of high temperature fluid from the RCPB or other high temperature systems.

A description of these monitors is provided in Section 7.5

6. Containment Pressure Monitors

An increase in Containment pressure can indicate a leak of high temperature fluid from the RCPB or other high temperature systems.

A description of these monitors is provided in Section 7.3.

7. Frequency and Duration of Operation of the Containment Sump Pumps.

Each pump is provided with a running time indicator which indicates in seconds the duration of pump operation. This indicator can be used to estimate gross leakage rates and can act as a backup to the discharge flow monitors.

8. Gross Leakage Indications

Gross leakage in the Containment can be indicated by:

a. Decrease in pressurizer level

b. Increase in the rate of supply of reactor coolant makeup water

c. Containment temperature monitors

d. Containment pressure monitors

e. Containment sump level high alarm

9. Liquid inventory

Reactor coolant volume can be indicative of system leakages. Net level changes in the pressurizer and volume control tank are functions of the system leakage because the Chemical Volume Control System is a closed loop system. Abnormal makeup requirements can be indicative of system leakage.

5.2.5.2.3 Intersystem Leakage Detection Method

Leakage of reactor coolant into secondary and auxiliary systems can occur as a result of equipment defects. As discussed previously, the principal leak path for primary coolant into other systems is through the steam generator tubes into the secondary side of the steam generator. An additional path is through faulty equipment (primarily RHR and SIS components) into the Component Cooling Water System (CCWS).

Leakage from the RCS into connected systems does not present a significant safety issue. During normal operation, the CVCS letdown line and charging line have fluid flow through them from and to the RCS, respectively; therefore, the question of RCS leakage detection is not applicable to these lines. In all other cases where the RCS and the ECCS, RHRS and CVCS are interconnected, the auxiliary systems are isolated from the RCS by at least seat leakage. Where appropriate, these isolation valves comply with the requirements of BTP EICSB 3, “Isolation of Low Pressure Systems from High Pressure Reactor Coolant Systems.”

Because of the isolation valves provided, any leakage into the connected systems would be at very low rates (cc’s/hr). For closed systems with design pressure equal to that of the RCS, the only effect of the leakage would be to pressurize a portion of the piping to RCS operating pressure. For closed systems with design pressures less than that of the RCS, the only effect would be to lift the relief valve provided. For open systems (surge volumes present), the only effect would be a slow increase in the surge volume level.

Leakage into the lower pressure connected systems is detected directly either by lifting of the relief valve or by any increase in the surge volume level. Other leakage detection methods discussed previously in Section 5.2.5.2.

Pressure indication is provided to monitor ECCS piping pressure during normal plant operations. Refer to Section 6.3.5.2.6 for more details.

5.2.5.3 Sensitivity and Response Time of Selected Leakage-Detection Systems

1. Containment Air Particulate Monitor

The Containment air particulate monitor is the most sensitive instrument available for detection of reactor coolant leakage into the Containment. This instrument is capable of detecting particulate activity in concentrations as low as 5×10^{-11} microcuries per cubic centimeter ($\mu Ci/cm^3$) in the Containment air sampled.

Using this concentration, calculations show that the particulate monitor, for a reference nuclide of Cs-137, can conservatively detect a 1.0-gpm increase in unidentified leakage within the Containment in less than one hour after the leak begins. The sensitivity of the containment airborne particulate and gas monitors for detection of 1 gpm primary coolant leakage is dependent of both the primary coolant activity level and the background radiation level in containment which vary with Reactor Power.

Conservative analysis indicates that the maximum pre-existing containment background levels that will not prevent reliable leak detection by the particulate monitor (without spurious alarms) will vary with changes in the primary coolant activity. The relation between failed fuel fraction, primary coolant activity and background levels for any specified condition may be derived from the general sensitivity equation in ANSI 13.10 and the time constants specified for the monitor used in this service. Operating experience has shown the particulate background radiation levels have remained low relative to the expected activity increase from 1gpm leak. Therefore, this monitor is expected to detect a 1gpm leak within one hour.

2. Containment Radioactive Gas Monitor

This system is less sensitive than the Containment air particulate monitor but gives a positive indication of leakage in the event that reactor coolant gaseous activity exists as a result of fuel-cladding defects. A one gallon per minute leakage from the primary coolant pressure boundary in the containment can be detected in less than one hour provided the containment atmosphere activity is below the level that would mask the activity corresponding to the leakage. If this system is one of the two required Leakage Detection System inoperable in MODES 1, 2, 3 and 4 operations may continue up to 30 days provided grab samples of the containment atmosphere are obtained and analyzed at least once per 24 hours.

Analysis also shows that the maximum pre-existing containment radioactive gaseous background levels for which reliable detection is possible will vary directly with the activity levels in the primary coolant. With primary coolant concentrations less than equilibrium levels, such as during startup, the increase in detector count rate due to leakage will be

partially masked by the statistical variation of the minimum detector background count rate, rendering reliable detection of a 1 gpm leak uncertain.

Operating experience has shown elevated gaseous background radiation levels will partially mask the detection of a 1 gpm leak. However, the monitor is capable of qualitatively detecting an RCS to containment atmosphere leak.

In conclusion, reliable leak detection is possible, provided that the equilibrium activity of the containment atmosphere is below the level that would mask the change in activity corresponding to a 1 gpm leak in one hour. Given the above limitations, the intent of the leak detection requirements of Regulatory Guide 1.45 is met in the following manner. The monitors are seismologically qualified as required in Section C of Regulatory Guide 1.45. The minimum sensitivities of the containment air particulate and the radioactive gas monitors are 5×10^{-11} μCi/ml (reference nuclide Cs-137) and 1×10^{-6} μCi/ml (reference nuclide Xe-133), respectively. These are the minimum detectable activities when situated in a 2.5 mR/hr, of 1 Mev Gamma background field, which is the normal maximum anticipated at the location of the monitors. These sensitivities meet or exceed the sensitivities required of these monitors by Section B of Regulatory Guide 1.45.

3. Condensate Measuring System

The measurement of the condensate flow from containment recirculation unit cooling coils gives a sensitive indication of increases in unidentified leakage into the Containment. Condensate flow from approximately 0-gpm to 4.0-gpm can be measured with this system. In the event of very low reactor coolant activity levels, this system provides the most sensitive indication of unidentified leakage.

4. Dewpoint Temperature Monitors

These instruments are sensitive to an increase in dew point of 1°F or greater.

5. Containment Sump Fill Rate Increased By ≥ 1 GPM Alarm

All open floor areas and the equipment room floors are sloped toward floor drains with the drain piping routed to containment sumps 1 or 2. By design, flow to the sumps is unimpeded. This ensures that all liquid leakage will be routed to the sumps.

The containment sumps are equipped with level switches and an alarm timer. A sump inleak increase of ≥ 1 gpm will activate the sump leak detection system by initiating the alarm timer which is set at an interval which allows detection of ≥ 1 gpm leak increase in less than one hour.

To ensure continued reliability of the leakage-detection system, the equipment described in this section complies with Paragraph 4.10 of IEEE 279-1971.

5.2.5.4 Seismic Performance

The airborne particulate and gaseous radioactivity monitoring systems are designed to remain functional when subjected to the SSE. In addition, the Containment temperature and pressure

monitors, which serve as backup, gross leakage indicators, are also part of the post accident monitoring system and are qualified for the SSE.

The Containment sump flow monitor is capable of performing its function following seismic events not requiring plant shutdown.

The remaining systems described herein are considered to perform alarm and backup indication functions only and are not seismically qualified.

5.2.5.5 Leakage Information Available In The Control Room

1. Identified Leakage

Information about the identified leakage described in Subsection 5.2.5.2.1 is provided in the Control Room as follows:

a. Reactor Coolant Drain Tank process status (level, pressure, flow) are available at the liquid waste processing panel. A common trouble alarm is sent to the Control Room.

b. Radiation levels exceeding preset levels in the steam generator blowdown and the condenser off-gas systems are alarmed.

c. The temperature of the reactor head flange leak-off connection is indicated and alarmed.

d. Temperatures of the pressurizer safety and relief valve discharge piping is indicated and alarmed.

e. Component cooling water surge tank level is indicated, recorded and alarmed. Component cooling water radiation monitors are provided with readouts.

f. Primary-to-secondary leak rate, as detected my N-16 levels in the Main Steam Lines, exceeding preset levels is alarmed.

2. Unidentified Leakage

The primary monitors described in Subsection 5.2.5.2.2 are all indicated, recorded and alarmed.

The 1-gpm sump fill rate increase alarm is not recorded; sump discharge flow rate is recorded and totalized, but not alarmed.

5.2.5.6 Sensitivity and Operability Tests

1. Radiation Monitors

The tests proposed to demonstrate operability and relative accuracy of the air particulate and radioactive gas monitors are discussed in Section 11.5 and 12.3.4.

2. Containment Sump Flow Monitoring

   The testing proposed to demonstrate operability of the Containment Sump Flow Monitoring System is discussed in Section 9.3.3.4.

3. Containment Sump Fill Rate Increase Of ≥ 1 GPM Alarm

   During refueling shutdown, water is introduced to each sump to confirm switch settings and alarm annunciation.

5.2.5.7 Differentiation Between Identified and Unidentified Leaks

Any increases above the background level of 1.0-gpm of unidentified leakage and 10-gpm identified leakage (other than primary-to-secondary leakage) are investigated and evaluated by the operator in order to locate the sources of leakage.

Examples of techniques which will be employed by the operator in locating the area of leakage are provided below:

1. Leakage occurring from the reactor vessel head to vessel closure joint is identifiable by an increase in temperature in the leak-off line provided at this joint.

2. Leakage occurring from the main steam supply system, feedwater system, or CCWS is identifiable by an increase in condensate monitor indication without associated increase in background radioactivity. The increased frequency of sump pump operation is also an indication as is the 1-gpm leak increase alarm in the Control Room.

3. Leakage occurring from the RCPB is usually identifiable by a simultaneous increase in condensate and radioactivity monitor indications.

4. Dewpoint temperature plant process computer data can assist operators in locating leakage points because of the various locations of the dew cells in the Containment.

5. Steam generator primary-to-secondary leakage is detected by the Steam Generator Blowdown Process Sample (SGBPS) Monitor (see Section 11.5.2.7.1), the Steam Generator Leak Rate (SGLRM) Monitors (see Section 11.5.2.6.13), and the Condenser Off-Gas Monitor (see 11.5.2.6.5).

   The SGBPS, SGLRM's, and the condenser vacuum pump gas monitors meet the criteria for detection of primary-to-secondary leakage at the limits noted in Section 5.2.5.1.4, Item 1. This is conservatively based on the reactor coolant activities given in Table 11.1-4 and the dilution of the reactor coolant by the entire mass of coolant in the secondary system. The analysis is also based on no condensate cleanup, steam generator moisture carryover, partition of iodine in the steam generator or condenser, or correction for detector efficiency, as well as zero blowdown flow.

   It should be noted that blowdown flowrate, moisture carryover, and condensate cleanup do not effect the condenser vacuum pump gas monitor which is calibrated to specifically detect Xe-133, generally the predominate noble gas in the system. However, when argon

is injected, as described in Section 11.5.2.6.5, Ar-41 will be the predominate gas in the system.

It should also be noted that the steam generator leak rate monitors are on-line monitors located on the Main Steam lines and are calibrated to specifically detect N-16. Therefore, blowdown flowrate, moisture carryover, and condensate cleanup do not affect the steam generator leak rate monitors.

6. Leakage of the reactor coolant to the CCWS is detectable by means of the radiation monitor (see Sections 9.2.2 and 11.5) in the CCWS.

7. Leakage of the reactor coolant outside Containment is detectable by plant vent gas monitors (see Section 11.5) and the airborne radioactivity monitors of the Safeguards Building (see Section 12.3.4).

8. An alternate relief path (Unit 2 only) is available to measure intersystem leakage as described in Section 5.2.5.2.1.

5.2.5.8 Adequacy of the Leakage Detection System

A normal level of 1-gpm or less in unidentified leakage is expected. The leakage-detection systems are capable of detecting leakage as low as 0.1-gpm using the air particulate monitor and as low as 1-gpm using the condensate flow rate and the sump level alarm. The sensitivity is reasonably adequate to detect an increase in unidentified leakage rate. In addition, the capacity of the reactor coolant makeup system and containment water removal are well above the proposed leakage limits provided in the Technical Specifications.

1. Identified Leakage

Identified leakage collected in the Reactor Coolant Drain Tank is measured indirectly. The operator calculates the leakage in gpm based on the level change of the tank or based on total quantity (gallons) of fluid discharged and the known time interval between readings.

Identified leakage flow rate to the steam generators is measured by means of radiation monitors on the Main Steam Lines (SGLRM's), Steam Generator Blowdown System and Condenser Off-Gas System.

2. Unidentified Leakage

The condensate flow from the containment cooling condensate measuring system has direct reading in gpm.

Gross flow from the containment sumps is totalized, and the total flow in gallons and the time interval between sump evacuations is available to the operator. The operator also has the running time for each pump (80-gpm pumps). A rate of level change increase in the sumps of 1 gpm or greater leakage is alarmed to the operators as "The Containment Sump Fill Rate Increase" and requires no readout conversion.

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3. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907, June 1972.

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8. NRC Letter dated April 14, 2003, from Robert A. Gramm to C. L. Terry, "Comanche Peak Nuclear Power Plant, Units 1 and 2 – Re: Relief from the Requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section III, Concerning Pressurizer Upper Level Instrumentation and Other Lines and Associated Components (TAC No.s MB6427 and MB6428).

TABLE 5.2-1
APPLICABLE CODE ADDENDA FOR REACTOR COOLANT SYSTEM COMPONENTS

Reactor vessel	ASME III, 1971 Ed. thru Winter 72
Reactor vessel closure head	ASME III, 1989 Ed. (Unit 1) ASME III, 1971 Ed. thru Summer 72 (Unit 2)
Steam generator	ASME III, 1989 Ed. (Unit 1) ASME III, 1971 Ed. thru Summer 73 (Unit 2)
Pressurizer	ASME III, 1974 Ed.
CRDM housing	ASME III, 1989 Ed. (Unit 1)
Full length	ASME III, 1974 Ed. (Unit 2)
CRDM head adapter	ASME III, 1989 Ed. (Unit 1) ASME III, 1971 Ed. thru Winter 72 (Unit 2)
Reactor coolant pump	ASME III, 1971 Ed. thru Summer 73
Reactor coolant pipe	ASME III, 1974 Ed. thru Summer 75
Surge lines	ASME III, 1974 Ed. thru Winter 75
Valves	
Pressurizer safety	ASME III, 1971 Ed. thru Winter 72
Motor operated	ASME III, 1974 Ed. thru Summer 74
Manual (3" and larger)	ASME III, 1971 Ed. thru Summer 73
Control	ASME III, 1974 Ed. thru Summer 75

TABLE 5.2-2
REACTOR COOLANT PRESSURE BOUNDARY MATERIALS CLASS 1
PRIMARY COMPONENTS

(Sheet 1 of 4)

Reactor Vessel Components	
Shell plates (other than core region)	SA-533 Gr. A, B or C, Class 1 or 2 (vacuum treated) (Unit 1)
Shell and head plates (other than core region)	SA-533, Gr. A, B or C, Class 1 or 2 (vacuum treated) (Unit 2)
Shell plates (core region)	SA-533, Gr. A or B, Class 1 (vacuum treated)
Replacement reactor vessel closure head	SA-508, Class 3 (Unit 1)
Shell, flange and nozzle forgings, nozzle safe ends	SA-508, Class 2 or 3, SA-182, Type F304 or F316
CRDM and/or ECCS appurtenances, upper head	SB-166 or 167 and SA-182, Type F304
Instrumentation tube appurtenances, lower head	SB-166 or 167 and SA-182, Type F304, F304L or F316
Closure studs, nuts, washers	SA-540, Class 3, Gr. B24
Core support pads	SB-166 with carbon less than 0.10%
Monitor tubes and vent pipe	SA-312 or 376, Type 304 or 316 or SB-167
Vessel supports, seal ledge and heat lifting lugs	SA-516, Gr. 70 quenched and tempered or SA-533, Gr. A, B C, Class 1 or 2 (vessel supports may be of weld metal build up of equivalent strength)
Cladding and buttering	Stainless steel weld metal analysis A-7 and Ni-Cr-Fe weld metal F-number 43

TABLE 5.2-2
REACTOR COOLANT PRESSURE BOUNDARY MATERIALS CLASS 1
PRIMARY COMPONENTS

(Sheet 2 of 4)

Steam Generator Components	
Pressure plates	SA-533, Gr. A, B or C, Class 1 or 2 (Unit 2)
Pressure forgings (including nozzles and tubesheet)	SA-508, Class 3a (Unit 1) SA-508, Class 2 or 3 (Unit 2)
Primary Nozzle safe ends	SA-336, Class 316LN (Forging) (Unit 1) Stainless steel weld metal (Unit 2)
Channel heads	SA-508, Class 3a (Unit 1) SA-533, Gr. A, B or C, Class 1 or 2 or SA-216, Gr. WCC (Unit 2)
Tubes	SB-163, Ni-Cr-Fe annealed Alloy 690 thermally treated (Unit 1) Alloy 600 thermally treated (Unit 2)
Cladding and buttering	Stainless steel weld metal analysis A-8 (Unit 1), A-7 (Unit 2) and Ni-Cr-Fe weld metal F-Number 43
Closure hardware	
Studs	SA-193, Gr. B7
Nuts	SA-194, Gr.7
Washers	SA-194, Gr. 7 (Unit 1) ASTM F-436 (Unit 2)
Pressurizer Components	
Pressure plates	SA-533, Gr. A, B or C, Class 1 or 2

TABLE 5.2-2
REACTOR COOLANT PRESSURE BOUNDARY MATERIALS CLASS 1
PRIMARY COMPONENTS

(Sheet 3 of 4)

Pressure forgings	SA-508, Class 2 or 3
Nozzle safe ends	SA-182 or 376, Type 316 or 316L and Ni-Cr-Fe weld metal F- Number 43
Cladding and buttering	Stainless steel weld metal analysis A-7 and Ni-Cr-Fe weld metal F-Number 43
Closure hardware	
Studs	SA-193, Gr. B7
Nuts	SA-194, Gr. 7
Washers	ASTM F-436
Pressurizer safety valve forgings	SA-182, Type F316
Reactor Coolant Pump	
Pressure forgings	SA-182, Type F304, F316, F347 or F348
Pressure casting	SA-351, Gr. CF8, CF8A or CF8M
Tube and pipe	SA-213, 376 or 312, seamless Type 304 or 316
Pressure plates	SA-240, Type 304 or 316
Bar material	SA-479, Type 304 or 316
Closure bolting	SA-193, 320, 540 or 453, Gr. 660
Flywheel	SA-533, Gr. B, Class 1

TABLE 5.2-2
REACTOR COOLANT PRESSURE BOUNDARY MATERIALS CLASS 1
PRIMARY COMPONENTS

(Sheet 4 of 4)

Reactor Coolant Piping	
Reactor coolant pipe	SA-376, Gr. 304N or SA-351, Gr. CF8A centrifugal casting.
Reactor coolant fittings, branch nozzles	SA-351, Gr. CF8A and SA-182, Code Case 1423-2, Gr. 304N
Surge line	SA-376, Gr. 304, 316 or F304N
Auxiliary piping 1/2 through 12 inch and wall schedules 40S through 80S (ahead of second isolation valve)	ANSI B36.19
All other auxiliary piping (ahead of second isolation valve)	ANSI B36.10
Socket weld fittings	ANSI B16.11
Piping flanges	ANSI B16.5
Full Length CRDM	
Pressure housing	SA-336 Type 304LN (Unit 1) SA-182, Gr. F304 or SA-351, Gr. CF8 (Unit 2)
Pressure forgings	SA-182, Gr. F304 or SA-336, Gr. F8
Bar material	SA-479, Type 304
Welding materials	SFA 5.4 and 5.9, Type 308 or 308L

TABLE 5.2-3
REACTOR COOLANT PRESSURE BOUNDARY MATERIALS CLASS 1 AND 2
AUXILIARY COMPONENTS

(Sheet 1 of 2)

Valves	
Bodys	SA-182, Type F316 or SA-351, Gr. CF8 or CF8m
Bonnets	SA-182, Type F316 or SA-351,Gr. CF8 or CF8M
Discs	SA-182, Type F316 or SA-564, Gr. 630, cond. 1100°F heat treatment A-567 Grade 1 (Stellite 21)
Stems	SA-182, Type F316 or SA-564, Gr. 630, cond. 1100°F heat treatment
Pressure retaining bolting	SA-453, Gr. 660
Pressure retaining nuts	SA-453, Gr. 660 or SA-194, Gr. 6
Auxiliary Heat Exchangers	
Heads	SA-240, Type 304
Nozzle necks	SA-182, Gr. F304
Tubes	SA-213, Type 304
Tubesheets	SA-182, Gr. F304
Shells	SA-240 and 312, Type 304
Auxiliary Pressure Vessels, Tanks, Filters, etc.	
Shells and heads	SA-240, Type 304 or SA-264 consisting of SA-537, Gr. C11 with stainless steel weld metal analysis A-8 cladding
Flanges and nozzles	SA-182, Gr. F304 and SA-105 or 350, Gr. LF2 and LF3 with stainless steel weld metal analysis A-8 cladding
Piping	SA-312 and 240, Type 304 or 316 seamless
Pipe fittings	SA-403, Type 304 seamless
Closure bolting and nuts	SA-193, Gr. B7 and SA-194, Gr. 2H

TABLE 5.2-3
REACTOR COOLANT PRESSURE BOUNDARY MATERIALS CLASS 1 AND 2
AUXILIARY COMPONENTS

(Sheet 2 of 2)

Auxiliary Pumps	
Pump casing and heads	SA-351, Gr. CF8 or CF8M and SA-182, Gr. F304 or F316
Flanges and nozzles	SA-182, Gr. F304 or F316 and SA-403, Gr. WP316L seamless
Piping	SA-312, Type 304 or 316 seamless
Stuffing or packing box cover	SA-351, Gr. CF8 or CF8M and SA-240, Type 304 or 316
Pipe fittings	SA-403, Gr. WP316L seamless
Closure bolting and nuts	SA-193, Gr. B6, B7 or B8M and SA-194, Gr. 2H or 8M, SA-193, Gr. B6, B7 or B8M, SA-453, Gr. 660, and nuts, SA-194, Gr. 2H, 8M and 6

TABLE 5.2-4
REACTOR VESSELS INTERNALS, INCLUDING EMERGENCY CORE COOLING SYSTEMS

Forgings	SA-182, Type F304
Plates	SA-240, Type 304
Pipes	SA-312, Type 304 seamless or SA-376, Type 304
Tubes	SA-213, Type 304
Bars	SA-479, Type 304 and 410
Castings	SA-351, Gr. CF8 or CF8A
Bolting	SA-193, Gr. B8M (65 MYS/90MTS) Code Case 1618 inconel-750 SA-461, Gr. 688
Nuts	SA-193, Gr. B8
Locking devices	SA-479, Type 304
Weld buttering	Stainless steel weld metal analysis A-7

TABLE 5.2-5
REACTOR COOLANT WATER CHEMISTRY SPECIFICATIONS

Oxygen, maximum (ppm)	Oxygen concentration of the reactor coolant is maintained at or below 0.10 ppm for plant operation above 250°F.
Chloride, maximum (ppm)	0.15
Fluoride, maximum (ppm)	0.15
Hydrogen (cc(STP)/Kg H_20)	25 to 50
Reactor power level above 1 MWt, excluding decay heat during subcritical operation	
pH control agent (Li^7OH)	Maintain Lithium in relationship with Boron within the required values to support a minimum hot full power operating pH_t range of $\geq$ 6.9 to a maximum target pH_t of 7.4 with a maximum lithium concentration of 6.0 ppm.
Boric acid (ppm B)	Variable from 0 to approximately 2500

TABLE 5.2-6A (Unit 1 - Historical)
PARAMETERS FROM WCAP-7769 WHICH ARE DIFFERENT FOR
COMANCHE PEAK

Engineered safeguards power (Mwt)	3579
Total steam generator safety valve capacity (1bm/hr)	18,191,000
Coolant flow (RCS) (gpm)	377,600
Average core mass velocity (10^6 1bm/hr-ft^2)	2.62
Inlet temperature (°F)	558
Average power density (kw/1)	124.5
Fuel loading (kg/1)	2.7
Full power steam flow per loop (1bm/sec)	1051
Nominal shell-side steam generator water mass per loop (1bm)	104,000
Nominal NSSS power (Mwt)[(a)]	3474

a) Unit 1 was 3427 MWt until completion of 1RF09.

TABLE 5.2-6B (Unit 2)
PARAMETERS FROM WCAP-7769 WHICH ARE DIFFERENT FOR
COMANCHE PEAK

Engineered safeguards power (Mwt)	3579
Total steam generator safety valve capacity (1bm/hr)	18,191,000
Coolant flow (RCS) (gpm)	377,600
Average core mass velocity (10^6 1bm/hr-ft^2)	2.62
Inlet temperature (°F)	558
Average power density (kw/1)	124.5
Fuel loading (kg/1)	2.7
Full power steam flow per loop (1bm/sec)	1051
Nominal shell-side steam generator water mass per loop (1bm)	104,000
Nominal NSSS power (Mwt)	3474

TABLE 5.2-7
CODE CASES USED ON SAFETY CLASS 1 COMPONENTS WITHIN THE REACTOR COOLANT PRESSURE BOUNDARY

(Sheet 1 of 2)

Steam Generator:

Unit 1

N-20-4	-	SB-163 Nickel-Chromium-Iron Tubing (Alloy 600 and 690) and Nickel-Iron Chromium Alloy 800 at a Specified Minimum Yield Strength of 40.0 Ksi and Cold Worked Alloy 800 at Yield Strength of 47.0 Ksi, Section III, Division 2, Class 2
2142-1	-	F Number grouping for Ni-Cr-Fe Classification UNS N06052 Filler Metal
2143-1	-	F Number grouping for Ni-Cr-Fe Classification UNS W86152 Weld Electrode

Unit 2

1528	-	High Strength Steel SA-508, Class 2 and SA-541, Class 2 Forgings, Section III, Class 1 Components
1484	-	SB-163 Nickel-Chromium-Iron Tubing (Alloy 600 and 690) and Nickel-Iron-Chromium Alloy 800 at a Specified Minimum Yield Strength of 40.0 Ksi Section III, Division 2, Class 2
1493-1	-	Post-Weld Heat Treatment Section I, III and VIII, Division 1 and 2
1355	-	Electroslag Welding, Section I, III and VIII, Division 1 and 2

Pressurizer:

1528	-	Same As Above

Piping:

1423-2	-	Wrought Type 304 and 316 with Nitrogen Added, Sections I, III, VIII, Division 1 and 2
N-122	-	January 21, 1985 “Stress Indices for Integral Structural Attachments, Class 1”
N-319	-	July 13, 1984 “Alternate Procedure for Evaluation of Stresses in Butt Welding Elbows in Class 1 Piping, Section III, Division 1”

TABLE 5.2-7
CODE CASES USED ON SAFETY CLASS 1 COMPONENTS WITHIN THE REACTOR COOLANT PRESSURE BOUNDARY

(Sheet 2 of 2)

N-391	-	November 28, 1983 “Procedure for Evaluation of the Design of Hollow Circular Cross Section Welded Attachments on Class 1 Piping”
N-397	-	February 20, 1984 “Alternate Rules to the Spectral Broadening Procedures of N-1226.3 for Class 1, 2 and 3 Piping”
N-411	-	September 17, 1984 “Alternate Damping Values for Seismic Analysis for Class 1, 2 and 3 Piping Systems”

Valves:

Flux Thimble Tubing:

1612	-	Use of Type 308 Stainless Steel Rod and Bar for Section III, Class 1, 2, 3 and CS construction
1649	-	Modified SA 453-GR 660 for Class 1, 2, 3 and CS construction
1553-1	-	Upset Heading and Roll Threading of SA-453 for High Temperature Bolting, Section III, Classes I, 2, 3 and MC

Reactor Vessel Bottom-Mounted Instrumentation:

N-378	-	Seal Table Material

5.3 REACTOR VESSEL

5.3.1 REACTOR VESSEL MATERIALS

5.3.1.1 Material Specifications

Material specifications are in accordance with the American Society of Mechanical Engineers (ASME) Code requirements and are given in Section 5.2.3.

5.3.1.2 Special Processes Used for Manufacturing and Fabrication

1. The vessel is Safety Class 1. Design and fabrication of the reactor vessel is carried out in strict accordance with ASME Code, Section III, Class 1 requirements. The head flanges and nozzles are manufactured as forgings. The cylindrical portion of the vessel is made up of several shells, each consisting of formed plates joined by full penetration longitudinal weld seams. The hemispherical heads are made from dished plates. The reactor vessel parts are joined by welding, using the single or multiple wire submerged arc.

2. The use of severely sensitized stainless steel as a pressure boundary material has been prohibited and has been eliminated by either a select choice of material or by programming the method of assembly.

3. Unit 1

   The surfaces of the guide studs are chrome plated to prevent possible galling of the mated parts.

   Unit 2

   The control rod drive mechanism head adaptor threads and surfaces of the guide studs are chrome plated to prevent possible galling of the mated parts.

4. At all locations in the reactor vessel where stainless steel and Inconel are joined, the final joining beads are Inconel weld metal in order to prevent cracking.

5. Core region shells fabricated of plate material have longitudinal welds which are angularly located away from the peak neutron exposure experienced in the vessel, where possible.

6. Unit 1

   The location of full penetration weld seams in the vessel bottom head are restricted to areas that permit accessibility during inservice inspection. There are no full penetration welds in the upper closure head.

   Unit 2

   The location of full penetration weld seams in the upper closure head and vessel bottom head are restricted to areas that permit accessibility during inservice inspection.

7. The stainless steel clad surfaces are sampled to assure that composition and delta ferrite requirements are met.

8. The procedure qualification for cladding low alloy steel (SA-508, Class 2) requires a special evaluation to assure freedom from underclad cracking.

9. Minimum preheat requirements have been established for pressure boundary welds using low alloy material. The preheat must be maintained either until (at least) an intermediate post weld heat treatment is completed or until the completion of welding. In the latter case, upon completion of welding, a low temperature (400°F minimum) post weld heat treatment is applied for 4 hours, followed by allowing the weldment to cool to ambient temperature. For primary nozzle to shell welds, preheat must be maintained until an intermediate or full post weld heat treatment is completed.

5.3.1.3 Special Methods for Nondestructive Examination

The nondestructive examination of the reactor vessel and its appurtenances is constructed in accordance with the ASME Code, Section III requirements; also numerous examinations are performed in addition to ASME Code, Section III requirements. Nondestructive examination of the vessel is discussed in the following sections and the reactor vessel quality assurance program is given in Table 5.3-1.

5.3.1.3.1 Ultrasonic Examination

1. In addition to the design code straight beam ultrasonic test, angle beam inspection of 100 percent of plate material is performed during fabrication to detect discontinuities that may be undetected by longitudinal wave examination.

2. In addition to the ASME Code, Section III, nondestructive examination, all full penetration ferritic pressure boundary welds and heat affected zones in the reactor vessel are ultrasonically examined during fabrication. This test is performed upon completion of the welding and intermediate heat treatment but prior to the final post weld heat treatment. See Section 5.3.3.7 for additional discussion of this examination.

3. In addition to ASME Code, Section III, nondestructive examination, all full penetration ferritic pressure boundary welds in the reactor vessel are ultrasonically inspected after hydrostatic testing to establish additional assurance that the vessel will pass the ASME Code, Section XI, preservice inspection. See Section 5.3.3.7 for additional discussion of this shop examination.

5.3.1.3.2 Penetrant Examinations

The partial penetration weld for the control rod drive mechanism head adaptors and the bottom instrumentation tubes are inspected by dye penetrant after the root pass in addition to code requirements. Core support block attachment welds are inspected by dye penetrant after the first layer of weld metal and after each 1/2 inch of weld metal. All clad surfaces and other vessel and head internal surfaces are inspected by dye penetrant after the hydrostatic test.

5.3.1.3.3 Magnetic Particle Examination

The magnetic particle examination requirements below are in addition to the magnetic particle examination requirements of Section III of the ASME Code. All magnetic particle examinations of materials and welds shall be performed in accordance with the following:

1. Prior to the final post weld heat treatment - Only by the Prod, Coil or Direct Contact Method.

2. After the final post weld heat treatment - Only by the Yoke Method.

The following surfaces and welds shall be examined by magnetic particle methods. The acceptance standards shall be in accordance with Section III of the ASME Code.

5.3.1.3.3.1 Surface Examinations

1. Magnetic particle examine all exterior vessel and heat surfaces after the hydrostatic test.

2. Magnetic particle examine all exterior closure stud surfaces and all nut surfaces after final machining or rolling. Continuous circular and longitudinal magnetization shall be used.

3. Magnetic particle examine all inside diameter surfaces of carbon and low alloy steel products that have their properties enhanced by accelerated cooling. This inspection to be performed after forming and machining (if performed) and prior to cladding.

5.3.1.3.3.2 Weld Examination

Magnetic particle examination of the weld metal buildup for vessel support welds attaching the closure head lifting lugs and refueling seal ledge to the reactor vessel after the first layer and each 1/2 inch of weld metal is deposited. All pressure boundary welds shall be examined after back chipping or back grinding operations.

5.3.1.4 Special Controls for Ferritic and Austenitic Stainless Steels

Welding of ferritic steels and austenitic stainless steels is discussed in Section 5.2.3. Section 5.2.3 includes discussions which indicate the degree of conformance with Regulatory Guides 1.31, “Control of Stainless Steel Welding,” and 1.44, “Control of the Use of Sensitized Stainless Steel.” Appendix 1A(N) discusses the degree of conformance with Regulatory Guides 1.34, “Control of Electroslag Weld Properties,” 1.43, “Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components,” 1.50, “Control of Preheat Temperature for Welding of Low-Alloy Steels,” 1.71, “Welder Qualification for Areas of Limited Accessibility,” and 1.99, “Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials.”

5.3.1.5 Fracture Toughness

Assurance of adequate fracture toughness of ferritic materials in the reactor coolant pressure boundary (ASME Code, Section III, Class 1 components) is provided by compliance with the requirements for fracture toughness testing included in NB-2300 to Section III of the ASME Code and Appendix G of 10CFR50.

The fasteners for the steam generators, pressurizers, reactor coolant pumps, and valves designed and fabricated to the ASME Code Summer 1973 Addendum or later (as specified in Table 5.2-1) comply with the requirements of 10CFR50 Appendix G as shown below. The only primary pressure boundary fasteners built to an earlier Code are the pressurizer safety valve fasteners, which were built to the ASME Code 1971 Edition, Winter 1972 Addendum.

		Fastener	Charpy Tests	
Code/Regulation	Diameter	ft. lbs.	MLE	Temperature
10CFR50 Appendix G	≤ 1" > 1"	No test required. 45	 25	Lower of preload or lowest service temperature.
ASME Code. 1971 Ed. Summer 1973 Addendum Later	≤ 1" > 1"	No test required. 45	 25	Lower of preload or lowest service temperature
ASME Code, 1971 Ed. Winter 1972 Addendum	≤ 1" > 1"	No test required. No req't	 25	40°F or lower

Since the fasteners for the pressurizer safety valves are less than 1 inch in diameter and since the preload and lowest service temperatures are expected to be greater than 40°F, compliance with the ASME Code ensures compliance with 10CFR50 Appendix G requirements. Fracture toughness properties of the reactor vessel fasteners are shown in Tables 5.3-3A, 5.3-3B, 5.3-4A, 5.3-4B and 5.3-4C.

The initial Charpy V-notch minimum upper shelf fracture energy levels for the reactor vessel beltline (including welds) shall be 75 foot pounds as required per Appendix G of 10CFR50. Materials having a section thickness greater than 10 inches with an upper shelf of less than 75 foot pounds shall be evaluated with regard to effects of chemistry (especially copper content), initial upper shelf energy and fluence to assure that a 50 foot pound shelf energy as required by Appendix G of 10CFR50 is maintained throughout the life of the vessel. The specimens shall be oriented as required by NB-2300 of Section III of the ASME Code.

Fracture toughness data for the Unit 1 and Unit 2 vessels are presented in Table 5.3-2A and B, respectively. Unit 1 and 2 reactor vessel beltline region material composition is given in Tables 5.3-6A and 5.3-6B. Fracture toughness properties at the beltline region for Units 1 and 2 reactor vessels are given in Tables 5.3-7A and 5.3-7B. Reactor vessel beltline weld and base metal charpy plots are given in Figures 5.3-2A through 5.3-4A for Unit 1, and Figures 5.3-2B through 5.3-4B for Unit 2. The same information is presented in tabular form in Tables 5.3-8A through 5.3-14A for Unit 1 and Tables 5.3-8B through 5.3-14B for Unit 2.

The reactor vessel non-beltline weld metal toughness properties are given in Table 5.3-15A for Unit 1 and Table 5.3-15B for Unit 2.

The steam generator and pressurizer base metal fracture toughness data are given in Table 5.3-16A for Unit 1 and Table 5.3-16B for Unit 2. The steam generator and pressurizer weld metal fracture toughness data are provided in Table 5.3-17A for Unit 1 and Table 5.3-17B for Unit 2. Plate locations are shown in Figures 5.3-1A and 5.3-1B.

Analysis had demonstrated that the closure flange regions for Units 1 and 2 are less limiting than the beltline regions [3].

5.3.1.6 Material Surveillance

5.3.1.6.1 Reactor Vessel Material Surveillance Capsules

In the surveillance program, the evaluation of the radiation damage is based on pre-irradiation testing of Charpy V-notch and tensile specimens and post-irradiation testing of Charpy V-notch, tensile and 1/2 T (thickness) compact tension (CT) fracture mechanics test specimens. The program is directed toward evaluation of the effect of radiation on the fracture toughness of reactor vessel steels based on the transition temperature approach and the fracture mechanics approach. The program will conform with ASTM E-185, “Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels,” and 10CFR50, Appendix H. The reports detailing the reactor vessel surveillance programs are listed in Reference section of the Pressure and Temperature Limits Report (PTLR) for Unit 1 and Unit 2 respectively.

The reactor vessel surveillance program uses six specimen capsules. The capsules are located in guide baskets welded to the outside of the neutron shield pads and are positioned directly opposite the center portion of the core. The capsules can be removed when the vessel head is removed and can be replaced when the internals are removed. The six capsules contain reactor vessel steel specimens, oriented both parallel and normal (longitudinal and transverse) to the principal rolling direction of the limiting base material located in the core region of the reactor vessel and associated weld metal and weld heat affected zone metal. The six capsules contain 54 tensile specimens, 360 Charpy V-notch specimens (which include weld metal and weld heat affected zone material), and 72 CT specimens. Archive material sufficient for two additional capsules will be retained.

Dosimeters, including nickel (Ni), copper (Cu), iron (Fe), cobalt- aluminum (Co-Al), cadmium (Cd) shielded Co-A1, Cd shielded neptunium-237 (Np-237), and Cd shielded uranium-238 (U-238), are placed in filler blocks drilled to contain them. The dosimeters permit evaluation of the flux seen by the specimens and the vessel wall. In addition, thermal monitors made of low melting point alloys are included to monitor the maximum temperature of the specimens. The specimens are enclosed in a tight fitting stainless steel sheath to prevent corrosion and ensure good thermal conductivity. The complete capsule is helium leak tested. As part of the surveillance program, a report of the residual elements in weight percent to the nearest 0.01 percent will be made for surveillance material and as deposited weld metal.

Each of the six capsules contains the following specimens:

Material	Number of Charpys	Number of Tensiles	Number of CT's
Limiting base material[a]	15	3	4
Limiting base material[b]	15	3	4
Weld metal[c]	15	3	4
Heat affected zone	15	-	-

a) Specimens oriented in the major rolling or working direction.

b) Specimens oriented normal to the major rolling or working direction.

c) Weld metal to be selected per ASTM-E-185.

The following dosimeters and thermal monitors are included in each of the six capsules:

1. Dosimeters
   - a. Fe.
   - b. Cu.
   - c. Ni.
   - d. Co-A1 (0.15 percent Co).
   - e. Co-A1 (Cd shielded).
   - f. U-238 (Cd shielded).
   - g. Np-237 (Cd shielded).
2. Thermal monitors
   - a. 97.5 percent palladium (Pd), 2.5 percent silver (Ag)(579°F melting point).
   - b. 97.5 percent Pd, 1.75 percent Ag, 0.75 percent tin (Sn)(590°F melting point).

The fast neutron exposure of the specimens occurs at a faster rate than that experienced by the vessel wall, with the specimens being located between the core and the vessel. Since these specimens experience accelerated exposure and are actual samples from the materials used in the vessel, the transition temperature shift measurements are representative of the vessel at a

later time in life. Data from CT fracture toughness specimens are expected to provide additional information for use in determining allowable stresses for irradiated material.

Correlations between the calculations and the measurements of the irradiated samples in the capsules, assuming the same neutron spectrum at the samples and the vessel inner wall, are described in Section 5.3.1.6.1.

They have indicated good agreement. Evaluation of surveillance specimen data will include the effects of specimen caused perturbations in the fast neutron flux and energy distribution. The calculated wall exposure will be verified and adjusted as necessary using data from all capsules removed. The schedule for removal of the capsules for post-irradiation testing is found in Section 2.4 of PTLR for the respective units.

5.3.1.6.1.1 Measurement of Integrated Fast Neutron (E > 1.0 MeV) Flux at the Irradiation Samples

In order to effect a correlation between fast neutron (E > 1.0 MeV) exposure and the radiation induced properties changes observed in the test specimens, a number of fast neutron flux monitors are included as an integral part of the reactor vessel surveillance program. In particular the surveillance capsules contain detectors employing the following reactions.

Fe^{54} (n,P) Mn^{54}

Ni^{58} (n,P) Co^{58}

Cu^{63} (n,α) Co^{60}

Np^{237}(n,f) Cs^{137}

U^{238} (n,f) Cs^{137}

In addition, thermal neutron flux monitors, in the form of bare and Cd shielded Co-A1 wire, are included within the capsules to enable an assessment of the effects of isotopic burnup on the response of the fast neutron detectors.

The use of activation detectors such as those listed above does not yield a direct measure of the energy dependent neutron flux level at the point of interest. Rather, the activation process is a measure of the integrated effect that the time and energy dependent neutron flux has on the target material. An accurate estimate of the average neutron flux level incident on the various detectors may be derived from the activation measurements only if the parameters of the irradiation are well known. In particular, the following variables are of interest:

1. The operating history of the reactor.

2. The energy response of the given detector.

3. The neutron energy spectrum at the detector location.

The procedure for the derivation of the fast neutron flux from the results of the Fe^{54}(n,P) Mn^{54} reaction is described below. The measurement technique for the other dosimeters, which are sensitive to different portions of the neutron energy spectrum, is similar.

The Mn^{54} product of the Fe^{54}(n,P) Mn^{54} reaction has a half life of 314 days and emits gamma rays of 0.84 MeV energy which are easily detected using a NaI scintillator. In irradiated steel samples, chemical separation of the Mn^{54} may be performed to ensure freedom from interfering activities. This separation is simple and very effective, yielding sources of very pure Mn^{54} activity. In some samples, all of the interferences may be corrected for by the gamma spectrometric methods without any chemical separation.

The analysis of the sample requires that two procedures be completed. First, the Mn^{54} disintegration rate per unit mass of sample and the Fe content of the sample must be measured as described above. Second, the neutron energy spectrum at the detector location must be calculated.

For this analysis, the DOT [1], two-dimensional multigroup discrete ordinates transport code is employed to calculate the spectral data at the location of interest. Briefly, the DOT calculations utilize a 21 group energy scheme, an S_8 order of angular quadrature, and a P_1 expansion of the scattering matrix to compute neutron radiation levels within the geometry of interest. The reactor geometry employed here includes a description of the radial regions internal to the primary concrete (core barrel, neutron pad, pressure vessel and water annuli) as well as the surveillance capsule and an appropriate reactor core fuel loading pattern and power distribution. Thus, distortions in the fission spectrum due to the attenuation of the reactor internals are accounted for in the analytical approach.

Having the measured activity, sample weight, and neutron energy spectrum at the location of interest, the calculation of the threshold flux is as follows:

The induced Mn^{54} activity in the Fe flux monitors may be expressed as:

$$D = \frac{No}{A} f_i \int_E \sigma(E)\varphi(E) \sum_{J=1}^{n} F_j(1 - e^{-\lambda\tau}J)e^{-\lambda\tau}d$$

where

D	=	induced Mn^{54} activity (dps/gm_{Fe})
No	=	Avogadro's number (atom/gm-atom)
A	=	atomic weight of Fe (gm/gm-atom)
fi	=	weight fraction Fe^{54} in the detector
σ(E)	=	energy dependent activation cross section for the Fe^{54} (n,P)Mn^{54} reaction (barns)

$\varphi(E)$ = energy dependent neutron flux at the detector at full reactor power (n/cm^2-sec)

λ = decay constant of Mn^{54} (1/sec)

F_j = fraction of full reactor power during the Jth time interval, τ_J

τ_j = length of the Jth irradiation period (sec)

τd = decay time following the Jth irradiation period (sec).

The parameters F_j, τ_J, and τ_d depend on the operating history of the reactor and the delay between capsule removal and saple counting.

The integral term in the above equation may be replaced by the following relation:

$$\int \sigma(E)\varphi(E) = \bar{\sigma}\bar{\varphi}_{E_{TH}} = \left\{ \frac{\sum_{0}^{\infty} \sigma_s(E)\varphi_s(E)}{\sum_{E_{TH}}^{\infty} \varphi_S \varphi} \right\} \bar{\varphi} E_{TH}$$

where

$\bar{\sigma}$ = effective spectrum average reaction cross section for neutrons above energy, E_{TH}

$\bar{\varphi}E_{TH}$ = average neutron flux above energy, E_{TH}

$\sigma_s(E)$ = multigroup $Fe^{54}(n,P)Mn^{54}$ reaction cross sections compatible with the DOT energy group structure

$\varphi_s(E)$ = multigroup energy spectra at the detector location obtained from the DOT analysis.

Thus,

$$D = \frac{No}{A} f_i \bar{\sigma}\bar{\varphi}E_{TH} \sum_{J=1}^{n} F_J(1 - e^{-\lambda\tau}J)e^{-\lambda\tau}d$$

or, solving for the threshold flux:

$$\bar{\varphi}E_{TH} = \frac{D}{\frac{No}{A} f_i \bar{\sigma} \sum_{J=1}^{n} F_J(1 - e^{-\lambda\tau J})e^{-\lambda\tau d}}$$

The total fluence above energy E_{TH} is given by:

$$\varphi_{E_{TH}} = \bar{\varphi}_{E_{TH}} \sum_{J=1}^{n} F_j \, \tau_J$$

where $\sum_{J=1}^{n} F_J \, \tau_J$ represents the total effective full power seconds of reactor operation up to the time of capsule removal.

Because of the relatively long half life of Mn^{54}, the fluence may be accurately calculated in this manner for irradiation periods up to about 2 years. Beyond this time, the calculated average flux begins to be weighted toward the later stages of irradiation and some inaccuracies may be introduced. At these longer irradiation times, therefore, more reliance must be placed on Np^{237} and U^{238} fission detectors with their 30 year life product (Cs^{137}).

No burnup correction was made to the measured activities, since burnout of the Mn^{54} product is not significant until the thermal flux level is about 10^{14} n/cm^2-sec.

The error involved in the measurement of the specific activity of the detector after irradiation is estimated to be ± 5 percent.

5.3.1.6.1.2 Calculation of Integrated Fast Neutron (E > 1.0 MeV) Flux at the Irradiation Samples

The energy and spatial distribution of neutron flux within the reactor geometry is obtained from the DOT [1] two-dimensional Sn transport code. The radial and azimuthal distributions are obtained from an R,θ computation wherein the reactor core as well as the water and steel annuli surrounding the core is modeled explicitly. The axial variations are then obtained from an R, Z DOT calculation using the equivalent cyclindrical core concept. The neutron flux at any point in the geometry is then given by:

$$\varphi\,(E, R, \theta, Z) = \varphi\,(E, R, \theta)F(Z)$$

Where φ (E, R, θ) is obtained directly from the R, θ calculation and F(Z) is a normalized function obtained from the R, Z analysis. The core power distributions used in both the R, θ and R,Z computations represent the expected average over the life of the station.

Having the calculated neutron flux distributions within the reactor geometry, the exposure of the capsule as well as the lead factor between the capsule and the vessel may be determined as follows:

The neutron flux at the surveillance capsule is given by:

$$\varphi_c = \varphi\ (E, R_c, \theta_c, Z_c)$$

and the flux at the location of peak exposure on the pressure vessel inner diameter is:

$$\varphi_{\ v-max} = \varphi\ (E, R_v, \theta_{\ v-max}, Z_{v-max})$$

The lead factor then becomes:

$$LF = \frac{\varphi_c}{\varphi_{\ v-max}}$$

Similar expressions may be developed for points within the pressure vessel wall, and, thus, together with the surveillance program dosimetry, serve to correlate the radiation induced damage to test specimens with that of the reactor vessel.

5.3.1.6.2 Ex-Vessel dosimetry

To achieve the goals of the Reactor Cavity Neutron Measurement Program, two types of measurements are made. Comprehensive sensor sets including radiometric monitors (RM) are employed at discrete locations within the reactor cavity to characterize the neutron energy spectrum variations axially and azimuthally over the beltline region of the reactor vessel. In addition, stainless steel gradient chains are used in conjunction with the encapsulated dosimeters to complete the mapping of the neutron environment between the discrete locations chosen for spectrum determinations.

5.3.1.6.2.1 Sensor Sets

The Reactor Cavity Neutron Measurement Program employs advanced sensor sets that are recommended by and are designed to the latest ASTM neutron dosimetry standards. The sensor sets consist of the following encapsulated dosimeters and gradient chains. The Table below lists the neutron reactions that are of interest.

1. Radiometric Monitors (RM) - these include cadmium shielded foils of the following metals: copper, titanium, iron, nickel, and cobalt-aluminum. Cadmium shielded fast fission reactions include ^{238}U and ^{237}Np in vanadium encapsulated oxide detectors. Bare iron and cobalt monitors are also included.

2. Gradient Chains - These stainless steel bead chains connect and support the dosimeter capsules containing the radiometric monitors. These segmented chains provide iron, nickel, and cobalt reactions that are used to complete the determination of the axial and azimuthal gradients. The high purity iron, nickel, and cobalt-aluminum foils contained in

the multiple foil sensor sets provide a direct correlation with the measured reaction rates from these gradient chains. These cross-comparisons permit the use of the gradient measurements to derive neutron flux distributions in the reactor cavity with a high level of confidence.

Table

Material	Reaction of Interest	Neutron Energy Response[a]	Product Half-Life	Dosimeter Capsule Position[b]	Gradient Chain[c]
Copper	$^{63}Cu(n,\alpha)^{60}Co$	6.13-11 MeV	5.271 yr	2-Cd	No
Titanium	$^{48}Ti(n,p)^{46}Sc$	3.86-9.4 MeV	83.81 dy	2-Cd	No
Iron	$^{54}Fe(n,p)^{54}Mn$	2.47-7.8 MeV	312.5 dy	1-B & 2-Cd	Yes
Nickel	$^{57}Ni(n,p)^{58}Co$	2.09-7.6 MeV	70.82 dy	2-Cd	Yes
^{238}U[d]	$^{238}U(n,f)^{137}Cs$	1.51-6.7 MeV	30.17 yr	3-Cd	No
^{237}Np[d]	$^{237}Np(n,f)^{137}Cs$	0.67-5.7 MeV	30.17 yr	3-Cd	No
Cobalt-Al	$^{59}Co(n,y)^{60}Co$	Thermal	5.271 yr	1-B & 2-Cd	Yes

Notes:

a) Energies between which 90% of activity is produced (^{235}U fission spectrum)

b) B denotes bare and Cd denotes cadmium shielded

c) Determined with additional chemical analysis

d) For the fission monitors ^{95}Zr (64.02 dy) and ^{103}Ru (39.27 dy) activities are also reported

5.3.1.6.2.2 Support Hardware and Installation

The sensor sets are located in the annular space between the reactor vessel reflective insulation and the primary biological shield at Comanche Peak Unit 1 and 2. The dosimetry installation consists of small aluminum dosimeter capsules connected to and supported by stainless steel bead chain.

The design of the dosimetry support system and the gradient chains and chain stops ensures correct and repeatable axial and azimuthal placement of the dosimetry relative to well known reactor features.

5.3.1.6.2.3 Supporting Analysis

Plant specific discrete ordinates transport theory calculations are performed to determine the neutron and gamma ray environment within the reactor geometry. The specific methods applied are consistent with those described in WCAP-15557, Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology, S. L. Anderson, August 2000 and will meet the requirements of Regulatory Guide RG-1.190, Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence, March 2001.

The transport calculations are carried out using the following three-dimensional synthesis technique:

$$\phi(r, \theta, z) = \phi(r, \theta) x \frac{\phi(r, z)}{\phi(r)}$$

where

$\phi(r, \theta, z)$	is the synthesized three-dimensional flux distribution,
$\phi(r, \theta)$	is the transport solution in r, θ geometry,
$\phi(r, z)$	is the two-dimensional solution for a cylindrical reactor model using the actual axial core power distribution, and
$\phi(r)$	is the one-dimensional solution for a cylindrical reactor model using the same source per unit height as that used in the two-dimensional r, θ calculation.

The transport calculations are performed using the DORT discrete ordinates transport theory code (ORNL RSICC CCC-650, August 1996) and the BUGLE-96 cross-section library (ORNL RSICC DLC-185, March 1996). The ENDF/B-VI based BUGLE-96 library is a 67 energy-group (47 neutron, 20 gamma ray) coupled neutron-gamma ray cross-section data set produced specifically for light-water reactor applications. In the transport analysis anisotropic scattering will be treated with a P_5 expansion of the cross-sections and angular discretization will be modeled with an S_{16} angular quadrature. An energy- and space-dependent fixed distributed source based on fuel cycle specific core power, burnup, and enrichment distributions will be used. In addition, system operating temperatures will be treated on a fuel cycle specific basis.

A detailed geometric model of the core, reactor internals, in-vessel surveillance capsules, reactor vessel, reflective insulation, and biological shield configuration is included in the transport calculations in order to ensure an accurate assessment of the relationship between the reactor vessel exposure and the measurements made in the surveillance capsules and in the reactor cavity.

The synthesis procedure combining the $\phi(r, \theta)$, $\phi(r, z)$, and $\phi(r)$ transport solutions into the three-dimensional flux / fluence maps within the reactor geometry is carried out using the Westinghouse developed SYNTHE post-processing code.

Evaluations of the neutron dosimetry sensor sets is done using the current state-of-the-art least squares methodology described in WCAP-15557. Best estimates for key exposure parameters

such as fast neutron flux (E > 1.0 MeV) or iron atom displacement rate (dpa/s) along with their uncertainties are then easily obtained from the adjusted spectrum. In general, the least squares methods, as applied to dosimetry evaluations, act to reconcile the measured sensor reaction rate data, dosimetry reaction cross-sections, and the calculated neutron energy spectrum within their respective uncertainties. For example,

$$R_i \pm \delta_{R_i} = \sum_g (\sigma_{ig} \pm \delta_{\sigma_{ig}})(\phi_g \pm \delta_{\phi_g})$$

relates a set of measured reactions, to a single neutron spectrum, through the multigroup dosimeter reaction cross-section, each with an uncertainty. The primary objective of the least squares evaluation is to produce unbiased estimates of the neutron exposure parameters at the location of the measurement.

The least squares evaluation of the dosimetry sets employs the FERRET code (ORNL RSICC PSR-145, January 1980) to combine the results of the plant specific neutron transport calculations and the sensor reaction rate measurements to determine best estimate values of fast neutron exposure parameters; e.g. neutron flux (E > 1.0 MeV), neutron flux (E > 0.1 MeV), and iron atom displacement rate (dpa/s) along with associated uncertainties.

The application of the least squares methodology requires the following input:

- The calculated neutron energy spectrum and associated uncertainties at the measurement location.
- The measured reaction rates and associated uncertainty for each sensor contained in the multiple foil sensor sets, and
- The energy dependent dosimetry reaction cross-sections and associated uncertainties for each sensor contained in the multiple foil sensor sets.

The calculated neutron energy spectrum is obtained from the results of the plant specific neutron transport calculations described above. The sensor reaction rates is derived from the measured specific activities for each dosimetry capsule analyzed. The dosimetry reaction cross-sections and uncertainties is obtained from the ENDF/B-VI based SNLRML dosimetry cross-section library (ORNL RSICC DLC-178, July 1994).

This approach is consistent with the requirements of Regulatory Guide RG-1.190, Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence, March 2001.

5.3.1.7 Reactor Vessel Fasteners

The reactor vessel closure studs, nuts, and washers are designed and fabricated in accordance with the requirements of the ASME Code, Section III. The closure studs are fabricated of SA-540, Class 3, Grade B24. The closure stud material meets the fracture toughness requirements of the ASME Code, Section III and 10CFR50, Appendix G. Conventional nuts and washers were originally supplied with the reactor vessel. Hydraulic nuts were procured to be used with the reactor vessel studs, as appropriate.

Compliance with Regulatory Guide 1.65, “Materials and Inspections for Reactor Vessel Closure Studs,” is discussed in Appendix 1A(N). Nondestructive examinations are performed in

accordance with the ASME Code, Section III. Fracture toughness data for Unit 1 and Unit 2 bolting materials are presented in Tables 5.3-3A,B and 5.3-4A,B,C.

Westinghouse refueling procedures require the studs, nuts and washers to be removed from the reactor closure and be placed in storage racks or stud covers installed over studs left in place during preparation for refueling. The storage racks are then removed from the refueling cavity and stored at convenient locations on the Containment operating deck prior to removal of the reactor closure head and refueling cavity flooding. Therefore the reactor closure studs are never exposed to the borated refueling cavity water.

Surface treatments and lubricants applied to the reactor vessel closure stud bolting are evaluated in accordance with the requirements of Regulatory Guide 1.65, Regulatory Position 1.b(3).

If reactor studs were removed then the stud holes in the reactor flange are sealed with special plugs before removing the reactor closure thus preventing leakage of the borated refueling water into the stud holes.

5.3.2 PRESSURE-TEMPERATURE LIMITS

5.3.2.1 Limit Curves

Limitations on pressure and temperature during startup and shutdown are based on controlling the stress in the reactor pressure vessel wall [2]. Rates of temperature change are controlled so the combination of thermally induced stress and stress from internal pressure will not exceed the stress needed to cause a flow, postulated in the vessel wall, to grow. The methods outlined in Appendix G of the ASME Code Section III describe the postulated flaw and the analysis that assures protection against brittle failure.

The beltline portion of the reactor vessel is nearest to the core and is therefore exposed to the most intense radiation. This intense radiation lowers the ability of the material to resist brittle failure and causes a corresponding decrease in the fracture toughness (K_I) of the material. Lower values of fracture toughness are related to higher values of nil-ductility temperature RT_{NDT}. Methods for determining the reference nil-ductility temperature are outlined in Regulatory Guide 1.99, “Radiation Embrittlement of Reactor Vessel Materials”, Revision 2 (See Section 1A(N) for Regulatory Guide 1.99).

The operating curves including pressure-temperature limitations are calculated in accordance with 10CFR50, Appendix G and ASME Code, Section III, Appendix G, requirements and are included in the Pressure Temperature Limits Report (PTLR). Changes in fracture toughness of the beltline plates of forgings, weldments and associated heat affected zones due to radiation damage will be monitored by a surveillance program which conforms with ASTM-E-185 and 10CFR50, Appendix H. Capsules containing specimens of these materials are located adjacent to the inner wall of the reactor pressure vessel, near the core midheight. Capsules are removed at intervals prescribed in Section 5.3.1.6.

Prior to withdrawal of the first capsule, the shift in the Adjusted Reference Temperature (ART) is determined from a calculated fluence and the copper and nickel content of the steel. When the capsule withdrawal sequence begins, the shift in reference temperature is determined by comparing Charpy V-notch results from specimens tested during preirradiation testing with

Charpy V-notch results from specimens in the capsules. Updated values of reference temperature will be used to revise operating curves if RT_{NDT} determined from the surveillance program is greater than the predicted RT_{NDT}.

Temperature limits for preservice hydrotests and inservice leak and hydrotests will be calculated in accordance with 10CFR50, Appendix G and are included in the Technical Specification 3.04.3 and the PTLR with the exception of the preservice limits.

5.3.2.2 Operating Procedures

The transient conditions that are considered in the design of the reactor vessel are presented in Section 3.9N.1.1. These transients are representative of the operating conditions that should prudently be considered to occur during plant operation. The transients selected form a conservative basis for evaluation of the RCS to insure the integrity of the RCS equipment.

Those transients listed as upset condition transients are listed in Table 3.9N-1. None of these transients will result in pressure-temperature changes which exceed the heatup and cooldown limitations as described in Section 5.3.2.1 and in Table 3.9N-1a.

5.3.2.2.1 10CFR50.61 Screening Values

The values of pressurized thermal shock reference temperature (RT_{PTS}) were calculated for each reactor vessel using the methodology required by 10CFR50.61. The Unit 1 reactor vessel has beltline region limiting end of life (EOL) RT_{PTS} value of 100°F. The Unit 2 reactor vessel has a beltline region limiting EOL RT_{PTS} value of 94°F. These values are well below the 10CFR50.61 screening values of 270°F and 300°F. Therefore no corrective actions associated with 10CFR50.61 are expected to be required during the operating life of CPNPP.

5.3.3 REACTOR VESSEL INTEGRITY

5.3.3.1 Design

The reactor vessel is cylindrical with a welded hemispherical bottom head and a removable, bolted, flanged, and gasketed, hemispherical upper head. The reactor vessel flange and head are sealed by two hollow metallic O-rings. Seal leakage is detected by means of two leakoff communications: one between the inner and outer ring and one outside the outer O-ring. The vessel contains the core, core support structures, control rods, and other parts directly associated with the core.

Unit 1

The Unit 1 reactor vessel closure head contains head adapters. These head adaptors are tubular members, attached by partial penetration welds to the underside of the closure head. The upper end of these allow for welding to the control rod drive mechanisms. There are also two penetrations for the Reactor Vessel Level Measuring System (RVLMS) and four penetrations for the Core Exit Thermocouple Nozzle Assemblies (CFTNA).

Unit 2

The Unit 2 reactor vessel closure head contains head adapters. These head adaptors are tubular members, attached by partial penetration welds to the underside of the closure head. The upper end of these adaptors contains asme threads for the assembly of control rod drive mechanisms or instrumentation adaptors. The seal arrangement at the upper end of these adaptors consists of a welded flexible canopy seal. Mechanical canopy seal clamp assemblies (CSCAs) may be used to contain or prevent leaks in the canopy seal. Leakage past the canopy seal or CSCA is not pressure boundary leakage.

Inlet and outlet nozzles are located symmetrically around the vessel. Outlet nozzles are arranged on the vessel to facilitate optimum layout of the RCS equipment. The inlet nozzles are tapered from the coolant loop vessel interfaces to the vessel inside wall to reduce loop pressure drop.

The bottom head of the vessel contains penetration nozzles for connection and entry of the nuclear incore instrumentation. Each nozzle consists of a tubular member made of either an Inconel or an Inconel-stainless steel composite tube. Each tube is attached to the inside of the bottom head by a partial penetration weld.

Internal surfaces of the vessel which are in contact with primary coolant are weld overlay with 0.125 inch minimum of stainless steel or Inconel. The exterior in the reactor vessel is insulated with canned stainless steel reflective sheets. The insulation is a minimum of 3 inches thick and contoured to enclose the top, sides and bottom of the vessel. All the insulation modules are removable but the access to vessel side insulation is limited by the surrounding concrete. The noncrushable nozzle insulation, which is a minimum of 5 inches thick, is removable provided the pressure restrictor plate and associated structures do not inhibit removal.

The reactor vessel is designed and fabricated in accordance with the requirements of the ASME Code, Section III.

Principal design parameters of the reactor vessel are given in Table 5.3-5.

There are no special design features which would prohibit the in-situ annealing of the vessel. If the unlikely need for an annealing operation was required to restore the properties of the vessel material opposite the reactor core because of neutron irradiation damage, a metal temperature greater than 650°F for a period of 168 hours maximum would be applied. Various modes of heating may be used depending on the temperature.

The reactor vessel materials surveillance program is adequate to accommodate the annealing of the reactor vessel. Sufficient specimens are available to evaluate the effects of the annealing treatment.

Cyclic loads are introduced by normal power changes, reactor trip, startup and shutdown operations. These design base cycles are selected for fatigue evaluation and constitute a conservative design envelope for the projected plant life. Vessel analysis results in a usage factor that is less than 1.

The design specifications require analysis to prove that the vessel is in compliance with the fatigue and stress limits of the ASME Code, Section III. The loadings and transients specified for the analysis are based on the most severe conditions expected during service. The heatup and

cooldown rates imposed by Technical Specifications are limited to 100°F per hour. The 100°F per hour limiting rate is reflected in the vessel design specifications.

5.3.3.2 Materials of Construction

The materials used in the fabrication of the reactor vessel are discussed in Section 5.2.3.

5.3.3.3 Fabrication Methods

The fabrication methods used in the construction of the reactor vessel are discussed in Section 5.3.1.2.

5.3.3.4 Inspection Requirements

The nondestructive examinations performed on the reactor vessel are described in Section 5.3.1.3.

5.3.3.5 Shipment and Installation

The reactor vessel is shipped in a horizontal position on a shipping sled with a vessel lifting truss assembly. All vessel openings are sealed to prevent the entrance of moisture and an adequate quantity of desiccant bags are placed inside the vessel. These are usually placed in a wire mesh basket attached to the vessel cover. All carbon steel surfaces are painted with a heat resistant paint before shipment except for the vessel support surfaces and the top surface of the external seal ring.

Unit 1

The Unit 1 replacement closure head is shipped with a protective shipping cover and skid. Two support plates within the shipping cover protect the control rod drive mechanism housings. All head openings are sealed to prevent the entrance of moisture and an adequate quantity of desiccant bags are placed inside the head. In addition, nitrogen purge is maintained to protect the control rod drive mechanism internals. The shipping cover also acts as a lifting frame for handling the replacement closure head.

Unit 2

The Unit 2 closure head is also shipped with a shipping cover and skid. An enclosure attached to the ventilation shroud support ring protects the control rod mechanism housings. All head openings are sealed to prevent the entrance of moisture and an adequate quantity of desiccant bags are placed inside the head. These are placed in a wire mesh basket attached to the head cover. All carbon steel surfaces are painted with heat resistant pain before shipment. A lifting frame is provided for handling the vessel head.

5.3.3.6 Operating Conditions

Operating limitations are presented in Section 5.3.2 and in the Core Operating Limits Report (COLR). The procedures and methods used to ensure the integrity of the reactor vessel under the most severe postulated conditions are described in Section 3.9N.1.4.

5.3.3.7 Inservice Surveillance

The internal surface of the reactor vessel is capable of inspection periodically using visual and/or nondestructive techniques over the accessible areas. During refueling, the vessel cladding is capable of being inspected in certain areas between the closure flange and the primary coolant inlet nozzles, and, if deemed necessary, the core barrel is capable of being removed, making the entire inside vessel surface accessible.

The closure head is accessible for examination during refueling. Optical devices permit a selective inspection of the cladding, control rod drive mechanism nozzles, and the gasket seating surface. For Unit 2, the knuckle transition piece, which is the area of highest stress of the closure head, is accessible on the outer surface for visual inspection, dye penetrant or magnetic particle, and ultrasonic testing. The closure studs can be inspected periodically using visual, magnetic particle and/or ultrasonic techniques.

The full penetration welds in the following areas of the installed irradiated reactor vessel are available for visual and/or nondestructive inspection.

1. Vessel shell - from the inside surface.

2. Primary coolant nozzles - from the inside surface.

3. Closure head - from the inside and outside surfaces. (Note: Unit 1 replacement head is a one-piece forging; therefore, full penetration weld on closure head has been eliminated.) Bottom head - from the outside surface.

4. Closure studs, nuts and washers.

5. Field welds between the reactor vessel, nozzles and the main coolant piping.

6. Vessel flange seal surface.

The design considerations which have been incorporated into the system design to permit the above inspection are as follows:

1. All reactor internals are completely removable. The tools and storage space required to permit these inspections are provided.

2. The closure head is stored dry on the vessel head storage stand during refueling to facilitate direct visual inspection.

3. All reactor vessel studs, nuts and washers can be removed to dry storage during refueling.

4. Removable plugs are provided in the primary shield. The insulation covering the nozzle welds may be removed.

The reactor vessel presents access problems because of the radiation levels and remote underwater accessibility to this component. Because of these limitations on access to the reactor vessel, several steps have been incorporated into the design and manufacturing

procedures in preparation for the periodic nondestructive tests which are required by the ASME inservice inspection code. These are:

1. Shop ultrasonic examinations are performed on all internally clad surfaces to an acceptance and repair standard to assure an adequate cladding bond to allow later ultrasonic testing of the base metal from inside surface. The size of cladding bonding defect allowed is 1/4 inch by 3/4 inch with the greater direction parallel to the weld in the region bounded by 2 T (T = wall thickness) on both sides of each full penetration pressure boundary weld. Unbounded areas exceeding 0.442 square inches (3/4 inch diameter) in all other regions are rejected.

2. The design of the reactor vessel shell is a clean, uncluttered cylindrical surface to permit future positioning of the test equipment without obstruction.

3. The weld deposited clad surface on both sides of the weld to be inspected is specifically prepared to assure meaningful ultrasonic examinations.

4. During fabrication, all full penetration ferritic pressure boundary welds are ultrasonically examined in addition to ASME Code, Section III, requirements. These examinations are performed with manual contact techniques using methods and acceptance criteria of Section XI of the ASME Code, 1974 Edition with addenda up to and including the Summer 1975.

5. After the shop hydrostatic testing, all full penetration ferritic pressure boundary welds are ultrasonically examined in addition to ASME Code, Section III, requirements. These examinations are performed with manual contact techniques using methods and acceptance criteria of Section XI of the ASME Code, 1974 Edition with addenda up to and including the Summer 1975.

The vessel design and construction enables inspection in accordance with the ASME Code, Section XI.

5.3.3.8 Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations (GL 97-01)

Beginning in 1986, leaks were reported in several Alloy 600 pressurizer instrument nozzles at both domestic and foreign reactors from several different NSSS vendors. The NRC staff identified primary water stress corrosion cracking (PWSCC) as an emerging technical issue to the Commission in 1989, after cracking was noted in Alloy 600 pressurizer heater sleeve penetrations at a domestic PWR facility. The NRC staff reviewed the safety significance of the cracking that occurred, as well as the repair and replacement activities at the affected facilities. The NRC staff determined that the cracking was not of immediate safety significance because the cracks were axial, had a low growth rate, were in a material with an extremely high flaw tolerance (high fracture toughness) and, accordingly, were unlikely to propogate very far. These factors also demonstrated that any cracking would result in detectable leakage and the opportunity to take corrective action before a penetration would fail. Further, with the exception of the leak found at Bugey 3 during hydrostatic testing, the NRC staff is not aware of any failure of any Alloy 600 vessel closure head penetration during plant operation. The NRC staff issued Information Notice (IN) 90-10, “Primary Water Stress Corrosion Cracking (PWSCC) of Inconel 600,” dated February 23, 1990, to inform the nuclear industry of the issue.

Unit 2 (Unit 1 RRVCH replaced Alloy 600 with Alloy 690)

CPNPP, as with most other PWRs, has Alloy 600 CRDM nozzle and other vessel head closure penetrations (VHPs) that extend above the reactor pressure vessel head. The stainless steel housing of the CRDM is screwed and seal-welded onto the top of the nozzle penetration. The weld between the nozzle top and bottom pieces is a dissimilar metal weld, which is also called a bimetallic weld. The nozzles protrude below the vessel head, thus exposing the inside surface of the nozzles to reactor coolant. The areas of interest for potential cracking are the weld between the nozzle and reactor vessel head, and the portion of the nozzle inside the reactor vessel head above the nozzle-to-vessel weld.

On April 1, 1997, the staff issued GL 97-01 to the industry, requesting that addressees provide a description of their plans to inspect the vessel head penetrations (VHPs) at their respective pressurized water reactor (PWR) designed plants. The Westinghouse Owners Group (WOG), in coordination with the efforts of the Nuclear Energy Institute (NEI) and the other PWR Owners Groups, determined that it was appropriate for its members to develop a cooperative integrated inspection program in response to GL 97-01. The WOG submitted two Topical Reports, WCAP-14901, Revision 0, “Background and Methodology for Evaluation of Reactor Vessel Closure Head Penetration Integrity for the Westinghouse Owners Group” and WCAP-14902, Revision 0, “Background Material for Response to NRC Generic Letter 97-01: Reactor Vessel Closure Head Penetration Integrity for the Westinghouse Owners Group” on behalf of the member utilities in the WOG. In these reports, the WOG provided descriptions of the two models, the Electric Power Research Institute (EPRI)/Dominion Engineering crack initiation and growth susceptibility model and the Westinghouse Model, that were being used to rank the VHPs at the participating plants in the owners group. CPNPP endorsed the probabilistic susceptibility model in Westinghouse Topical Report WCAP-14901, Revision 0, as being applicable to the assessment of VHPs at CPNPP, Units 1 and 2 [4].

REFERENCES

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2. Hazelton, W. S., et al., “Basis for Heatup and Cooldown Limit Curves,” WCAP-7924-A, April 1975.

3. Letter TXX-4170, dated May 16, 1984, H.C. Schmidt (TUGCO) to B.J. Youngblood (NRC).

4. WCAP-14901, Revision 0, “Background and Methodology for Evaluation of Reactor Vessel Closure Head Penetration Integrity for the Westinghouse Owners Group”.

TABLE 5.3-1
REACTOR VESSEL QUALITY ASSURANCE PROGRAM

(Sheet 1 of 2)

	RT[a]	UT[b]	PT[c]	MT[d]
Forgings				
Closure Head (Unit 1)		yes		yes
Vessel Flange (Unit 1)		yes		yes
Vessel and head flanges (Unit 2)		yes		yes
Studs and nuts		yes		yes
Head adapters		yes	yes	
Head adapter tube		yes	yes	
Instrumentation tube		yes	yes	
Main nozzles		yes		yes
Nozzle safe ends		yes	yes	
Plates		yes		yes
Weldments				
Main seam	yes	yes		yes
Control rod drive head adapter connection			yes	
Instrumentation tube connection			yes	
Main nozzle	yes	yes		yes
Cladding		yes	yes	
Nozzle safe ends (if forging)	yes	yes	yes	
Nozzle safe ends (if weld deposit)	yes	yes	yes	
Head adapter forging to head adapter tube	yes		yes	
All ferritic welds accessible after hydrotest		yes		yes

TABLE 5.3-1
REACTOR VESSEL QUALITY ASSURANCE PROGRAM

(Sheet 2 of 2)

	RT[a]	UT[b]	PT[c]	MT[d]
All non-ferritic welds accessible after hydrotest		yes	yes	
Seal ledge				yes
Head lift lugs				yes
Core pad welds			yes	

a) RT - Radiographic.

b) UT - Ultrasonic.

c) PT - Dye penetrant.

d) MT - Magnetic particle.

TABLE 5.3-2A
UNIT 1 REACTOR VESSEL FRACTURE TOUGHNESS PROPERTIES

(Sheet 1 of 2)

Component	Material	Code Number	Cu (%)	P (%)	Ni (%)	^{T}NDT(°F)	50 ft-lb 35 Mil. Temperature (°F)	^{RT}NDT (°F)	Average Shelf Energy MWD[a] (ft-lb)	Average Shelf Energy NMWD[b] (ft-lb)
Closure Head Forging	A508, C3	-	0.05	-	0.87	-50	10	-50	-	184.0
Vessel Flange	A508, C1.2	R1101-1	-	-	.72	10	70	10	-	97.0
Inlet Nozzle	A508, C1.2	R1105-1	0.09	-	.82	-10	50	-10	-	147.0
Inlet Nozzle	A508, C1.2	R1105-2	0.11	-	.84	-20	40	-20	-	136.5
Inlet Nozzle	A508, C1.2	R1105-3	0.11	-	.81	-10	50	-10	-	134.0
Inlet Nozzle	A508, C1.2	R1105-4	0.09	-	.82	-10	50	-10	-	156.5
Outlet Nozzle	A508, C1.2	R1106-1	-	-	.68	-20	40	-20	-	135.0
Outlet Nozzle	A508, C1.2	R1106-2	-	-	.62	-10	50	-10	-	111.0
Outlet Nozzle	A508, C1.2	R1106-3	-	-	.64	-20	50	-10	-	135.5
Outlet Nozzle	A508, C1.2	R1106-4	-	-	.65	-20	40	-20	-	117.5
Upper Shell	A533B, C1.1	R1104-1	0.07	0.012	.61	-30	100	40	-	83.0
Upper Shell	A533B, C1.1	R1104-2	0.08	0.011	.67	-50	100	40	-	75.0
Upper Shell	A533B, C1.1	R1104-3	0.05	0.010	.60	-20	70	10	-	107.5
Inter. Shell	A533B, C1.1	R1107-1	0.06	0.010	.65	-20	70	10	111.5	93.5
Inter. Shell	A533B, C1.1	R1107-2	0.06	0.010	.64	-20	50	-10	123.5	103.0
Inter. Shell	A533B, C1.1	R1107-3	0.05	0.007	.68	-20	70	10	131.0	88.0
Lower Shell	A533B, C1.1	R1108-1	0.08	0.008	.64	-20	60	0	119.0	85.0
Lower Shell	A533B, C1.1	R1108-2	0.05	0.006	.59	-30	80	20	124.5	78.0

TABLE 5.3-2A
UNIT 1 REACTOR VESSEL FRACTURE TOUGHNESS PROPERTIES

(Sheet 2 of 2)

Component	Material	Code Number	Cu (%)	P (%)	Ni (%)	^{T}NDT(°F)	50 ft-lb 35 Mil. Temperature (°F)	^{RT}NDT (°F)	Average Shelf Energy MWD[a] (ft-lb)	Average Shelf Energy NMWD[b] (ft-lb)
Lower Shell	A533B, C1.1	R1108-3	0.07	0.008	.64	-30	60	0	122.0	98.0
Bottom Head Torus	A533B, C1.1	R1112-1	0.13	0.010	.62	-50	50	-10	-	112.0
Bottom Head Dome	A533B, C1.1	R1113-1	0.08	0.010	.60	-50	70	10	-	90.0
Inter. & Lower Shell[c] (Long & Girth Weld Seams)		G1.67	0.04	0.008	.17	-70	-10	-70	-	150.0

a) Major working direction (Longitudinal)

b) Normal to major working direction (Transverse)

c) B4 Weld Wire HT 88112 & Linde 0091 Flux Lot No. 0145

TABLE 5.3-2B
UNIT 2 REACTOR VESSEL FRACTURE TOUGHNESS PROPERTIES

(Sheet 1 of 2)

Component	Material	Code Number	Cu (%)	Ni (%)	P (%)	NDT (°F)	50 ft-lb 35 Mil. Temperature (°F)	^{RT}NDT (°F)	Average Shelf Energy	
									MWD[a] (ft-lb)	NMWD[b] (ft-lb)
Closure Head Dome	A533B, C1.1	R3811-1	0.15	.65	0.014	-40	60	0	-	131
Closure Head Torus	A533B, C1.1	R3810-1	0.15	.69	0.011	-30	30	-30	-	143
Closure Head Flange	A508, C1.2	R3802-1	-	.71	0.013	40	<100	40	-	152
Vessel Flange	A508, C1.2	R3801-1	-	.70	0.009	-10	< 50	-10	-	121
Inlet Nozzle	A508, C1.2	R3803-1	-	.84	0.009	-10	< 50	-10	-	138
Inlet Nozzle	A508, C1.2	R3803-2	0.10	.91	0.008	-20	< 40	-20	-	136
Inlet Nozzle	A508, C1.2	R3803-3	-	.91	0.010	-10	< 50	-10	-	146
Inlet Nozzle	A508, C1.2	A3803-4	-	.86	0.009	-20	< 40	-20	-	136
Outlet Nozzle	A508, C1.2	A3805-1	-	.64	0.006	0	< 60	0	-	132
Outlet Nozzle	A508, C1.2	A3805-2	-	.66	0.005	0	< 60	0	-	119
Outlet Nozzle	A508, C1.2	A3805-3	-	.66	0.004	0	< 60	0	-	117
Outlet Nozzle	A508, C1.2	A3805-4	-	.67	0.005	0	< 60	0	-	119
Nozzle Shell	A533B, C1.1	A3806-1	0.05	.61	0.010	-10	100	40	-	76
Nozzle Shell	A533B, C1.1	A3806-2	0.06	.62	0.009	-30	70	10	-	87
Nozzle Shell	A533B, C1.1	A3806-3	0.06	.70	0.007	-30	100	40	-	86
Inter. Shell	A533B, C1.1	A3807-1	0.06	.64	0.006	-20	< 40	-20	133	108
Inter. Shell	A533B, C1.1	A3807-2	0.06	.64	0.007	-20	70	10	122	101
Inter. Shell	A533B, C1.1	A3807-3	0.05	.60	0.007	-20	40	-20	120	105

TABLE 5.3-2B
UNIT 2 REACTOR VESSEL FRACTURE TOUGHNESS PROPERTIES

(Sheet 2 of 2)

Component	Material	Code Number	Cu (%)	Ni (%)	P (%)	NDT (°F)	50 ft-lb 35 Mil. Temperature (°F)	^{RT}NDT (°F)	Average Shelf Energy MWD[a] (ft-lb)	Average Shelf Energy NMWD[b] (ft-lb)
Lower Shell	A533B, C1.1	A3816-1	0.05	.59	0.001	-30	30	-30	136	107
Lower Shell	A533B, C1.1	A3816-2	0.03	.65	0.002	-30	60	0	131	106
Lower Shell	A533B, C1.1	A3816-3	0.04	.63	0.008	-40	20	-40	139	108
Bottom Head Torus	A533B, C1.1	A3813-1	0.12	.65	0.009	-60	0	-60	-	123
Bottom Head Dome	A533B, C1.1	A3814-1	0.12	.66	0.009	-70	-10	-70	-	112
Weld Metal[c] (Inter. to Lower Shell Girth Seam)			0.05	.03	0.004	-60	<0	-60	-	96
Weld Metal[d] (Inter. & Lower Shell Long Seams)			0.07	.05	0.005	-50	<10	-50	-	172

a) Major working direction (Longitudinal)

b) Normal to major working direction (Transverse)

c) B4 Weld Wire Ht. 89833 & Linde 124 Flux Lot No. 1061

d) B4 Weld Wire Ht. 89833 & Linde 0091 Flux Lot No. 1054

TABLE 5.3-2C
UNIT 1 REACTOR VESSEL BELTLINE REGION TENSILE PROPERTIES AND MATERIAL HEAT TREATMENT

Component	Material	Test Temp.	0.2% YS (ksi)	UTS (ksi)	Elong. (%)	RA (%)
Inter. Shell	Plate R1107-1	Room	71.3	90.8	25.0	63.8
Inter. Shell	Plate R1107-1	Room	69.7	88.8	25.0	62.9
Inter. Shell	Plate R1107-2	Room	68.7	89.0	25.0	64.5
Inter. Shell	Plate R1107-2	Room	69.1	89.6	25.0	64.5
Inter. Shell	Plate R1107-3	Room	71.3	92.6	25.0	62.6
Inter. Shell	Plate R1107-3	Room	71.9	93.0	25.0	61.3
Inter. Lower	Plate R1108-1	Room	68.3	88.9	25.0	59.5
Inter. Lower	Plate R1108-1	Room	68.8	88.8	25.0	59.9
Inter. Lower	Plate R1108-2	Room	65.7	86.6	24.0	56.6
Inter. Lower	Plate R1108-2	Room	66.0	87.1	24.0	58.4
Inter. Lower	Plate R1108-3	Room	66.1	86.6	26.0	60.7
Inter. Lower	Plate R1108-3	Room	65.3	86.6	26.0	63.8
Inter. to Lower Shell Girth Weld Seam	G1.67[(a)]	Room	77.1	88.5	28.0	71.1

a) B4 Weld Wire Heat 88112 & Linde 0091 Flux Lot 0145

Component	Heat Treatment
Inter. and Lower Shell Plates	1600°F ±25°F - 4 Hours. Water quenched 1225°F ±25°F - 4 Hours 1150°F +50°F - 40 Hours. Furnace Cooled to 600°F
Inter. and Lower Shell Welds	1150°F +50°F - 40 Hours. Furnace Cooled to 600°F

TABLE 5.3-2D
UNIT 2 REACTOR VESSEL BELTLINE REGION TENSILE PROPERTIES AND MATERIAL HEAT TREATMENT

Component	Material	Test Temp.	0.2% YS (ksi)	UTS (ksi)	Elong. (%)	RA (%)
Inter. Shell	Plate R3807-1	Room	66.9	85.8	27.5	64.8
Inter. Shell	Plate R3807-1	Room	66.7	85.6	27.0	64.1
Inter. Shell	Plate R3807-2	Room	67.8	88.5	25.0	63.0
Inter. Shell	Plate R3807-2	Room	67.9	88.3	25.0	62.1
Inter. Shell	Plate R3807-3	Room	68.8	87.9	27.0	62.3
Inter. Shell	Plate R3807-3	Room	68.5	88.0	25.0	63.5
Inter. Lower	Plate R3816-1	Room	67.8	87.6	26.0	66.5
Inter. Lower	Plate R3816-1	Room	67.8	87.4	26.0	66.5
Inter. Lower	Plate R3816-2	Room	67.3	88.1	27.0	62.6
Inter. Lower	Plate R3816-2	Room	67.2	87.6	27.0	62.9
Inter. Lower	Plate R3816-3	Room	68.7	89.8	25.5	62.9
Inter. Lower	Plate R3816-3	Room	69.0	89.1	25.5	64.2
Inter. to Lower Shell Girth Weld Seam	E3.10[a]	Room	70.8	86.4	27.0	65.4
Inter. to Lower Shell Long. Weld Seam	G3.03[b]	Room	67.9	80.6	30.0	71.0

a) B4 Weld Wire Heat 89833 & Linde 124 Flux Lot 1061

b) B4 Weld Wire Heat 89833 & Linde 0091 Flux Lot 1054

Component	Heat Treatment
Inter. and Lower Shell Plates	1600°F ±25°F - 4 Hours. Water quenched 1225°F ±25°F - 4 Hours 1150°F +50°F - 40 Hours. Furnace Cooled to 600°F
Inter. and Lower Shell Welds	1150°F +50°F - 40 Hours. Furnace Cooled to 600°F

TABLE 5.3-3A
UNIT 1 REACTOR PRESSURE VESSEL CLOSURE BOLTING MATERIAL PROPERTIES – STUDS

Heat Number	Material	Bar Number	0.2% Yield Stress (ksi)	Ultimate Tensile Strength (ksi)	Elongation (%)	Reduction in Area (%)	Brinell Hardness Number	Energy at 10°F (ft-lbs)	Lateral Expansion(mils)
84176	A540, B24	412	148.7	163.5	15.0	49.2	352	46, 47, 46	25, 28, 26
84176	A540, B24	412-1	143.5	158.0	16.5	51.5	341	51, 50, 53	28, 29, 28
84176	A540, B24	419	147.5	161.5	16.0	51.4	341	50, 50, 50	28, 29, 28
84176	A540, B24	419-1	142.5	157.0	16.5	52.8	331	50, 51, 50	31, 33, 30
84176	A540, B24	423	144.0	159.0	16.5	51.9	341	48, 50, 50	26, 29, 30
84176	A540, B24	423-1	147.5	163.0	16.0	52.2	331	50, 52, 51	30, 31, 30
84176	A540, B24	425	150.2	164.0	15.0	50.0	341	45, 46, 45	28, 27, 26
84176	A540, B24	425-1	146.5	161.0	16.0	51.8	341	49, 49, 49	31, 29, 33
84176	A540, B24	428	148.5	163.0	17.0	51.4	341	48, 49, 48	28, 29, 28
84176	A540, B24	428-1	142.5	156.0	16.5	49.0	341	48, 49, 49	29, 31, 29
83833	A540, B24	410	137.7	155.0	17.0	55.2	321	53, 54, 53	34, 34, 32
83833	A540, B24	410-1	148.2	164.0	16.0	51.4	341	51, 50, 50	30, 29, 27
43320	A540, B24	459	137.2	153.0	17.0	53.4	331	48, 47, 48	30, 30, 28
43320	A540, B24	459-1	136.2	151.5	17.0	53.2	331	49, 48, 46	31, 28, 28

TABLE 5.3-3B
UNIT 2 REACTOR VESSEL CLOSURE HEAD BOLTING MATERIAL PROPERTIES – STUDS

(Sheet 1 of 2)

Heat Number	Material	Bar Number	0.2% Yield Stress (ksi)	Ultimate Tensile Strength (ksi)	Elongation (%)	Reduction in Area (%)	Brinell Hardness Number	Energy at 10°F (ft-lbs)	Lateral Expansion(mils)
85695	SA540, B24	695	138.5	153.0	18.0	56.2	331	54, 54, 52	33, 33, 31
85695	SA540, B24	695-1	140.0	155.0	17.5	55.2	341	50, 52, 52	30, 34, 30
85695	SA540, B24	699	142.5	157.0	17.5	56.0	341	49, 50, 50	30, 31, 32
85695	SA540, B24	699-1	139.5	154.0	18.0	56.2	341	50, 49, 48	31, 29, 30
85695	SA540, B24	700	142.5	157.0	17.5	53.6	331	50, 49, 48	29, 29, 30
85695	SA540, B24	700-1	140.0	155.0	17.5	54.1	331	52, 53, 53	31, 33, 33
85695	SA540, B24	706	141.5	156.0	17.0	55.7	341	51, 51, 52	30, 32, 33
85695	SA540, B24	706-1	140.0	154.0	18.0	56.5	341	52, 53, 53	32, 33, 33
85695	SA540, B24	711	138.5	152.0	17.5	55.7	331	52, 54, 51	34, 34, 31
85695	SA540, B24	711-1	138.2	153.0	18.0	56.2	321	50, 50, 49	32, 31, 30
85695	SA540, B24	713	141.0	155.5	17.0	54.1	331	48, 50, 51	29, 29, 31
85695	SA540, B24	713-1	142.0	157.0	17.5	54.7	341	50, 50, 50	32, 29, 30
85919	SA540, B24	740	142.0	156.0	17.5	51.4	331	55, 54, 55	35, 35, 34
85919	SA540, B24	740-1	142.0	155.0	17.5	52.5	341	54, 53, 55	34, 33, 34
85919	SA540, B24	744	135.2	150.0	17.5	51.9	331	55, 56, 56	34, 36, 35
85919	SA540, B24	744-1	144.7	158.0	16.5	50.6	331	52, 54, 52	32, 33, 31

TABLE 5.3-3B
UNIT 2 REACTOR VESSEL CLOSURE HEAD BOLTING MATERIAL PROPERTIES – STUDS

(Sheet 2 of 2)

Heat Number	Material	Bar Number	0.2% Yield Stress (ksi)	Ultimate Tensile Strength (ksi)	Elongation (%)	Reduction in Area (%)	Brinell Hardness Number	Energy at 10°F (ft-lbs)	Lateral Expansion(mils)
85919	SA540, B24	748	137.2	152.0	17.0	53.3	341	54, 55, 55	34, 36, 33
85919	SA540, B24	748-1	141.0	154.5	17.0	52.2	341	56, 55, 57	33, 34, 34
85919	SA540, B24	752	142.0	156.0	16.5	50.0	331	56, 56, 55	34, 34, 36
85919	SA540, B24	752-1	140.0	155.0	17.0	53.3	341	55, 53, 54	33, 33, 31
85919	SA540, B24	754	140.0	155.0	16.5	50.0	331	56, 56, 54	36, 37, 33
85919	SA540, B24	754-1	142.2	156.0	17.0	52.5	341	57, 54, 56	35, 34, 38
85919	SA540, B24	760	141.0	155.5	17.5	53.3	341	58, 58, 57	37, 38, 36
85919	SA540, B24	760-1	142.7	157.5	17.0	52.5	341	52, 52, 53	31, 31, 33

TABLE 5.3-4A
UNIT 1 REACTOR PRESSURE VESSEL CLOSURE BOLTING MATERIAL PROPERTIES - NUTS AND WASHERS

Heat Number	Material	Tube Number	0.2% Yield Stress (ksi)	Ultimate Tensile Strength (ksi)	Elongation (%)	Reduction in Area (%)	Brinell Hardness Number	Energy at 10^{o}F (ft-lbs)	Lateral Expansion(mils)
63182	A540, B24	132	148.0	162.0	17.5	57.3	331	51, 52, 51	31, 32, 30
63182	A540, B24	132-1	148.7	162.0	17.0	54.7	331	49, 48, 49	29, 26, 29
63182	A540, B24	133	147.2	161.0	17.0	55.2	321	52, 50, 51	31, 30, 30
63182	A540, B24	133-1	y149.2	162.5	17.5	54.7	331	51, 51, 49	29, 31, 27
63182	A540, B24	135	147.5	161.0	17.0	53.0	321	49, 49, 51	28, 29, 30
63182	A540, B24	135-1	143.2	157.0	17.5	55.2	321	55, 54, 52	33, 32, 31
63182	A540, B24	137	145.0	159.0	16.5	54.8	331	54, 54, 53	33, 33, 29
63182	A540, B24	137-1	147.0	160.0	17.0	55.7	321	54, 55, 54	34, 36, 33
63182	A540, B24	143	145.0	159.0	18.0	58.1	331	55, 54, 54	33, 32, 32
63182	A540, B24	143-1	147.0	160.0	17.0	57.3	321	54, 50, 52	33, 29, 30
63182	A540, B24	145	145.0	159.0	17.0	56.0	321	54, 54, 55	34, 35, 34
63182	A540, B24	145-1	146.2	159.7	17.0	57.0	331	56, 55, 54	36, 35, 36
63182	A540, B24	148	144.0	157.5	17.5	56.5	331	56, 55, 55	33, 34, 34
63182	A540, B24	148-1	148.5	162.0	17.0	55.6	321	52, 51, 52	33, 28, 30
63182	A540, B24	150	144.7	158.0	17.5	55.7	331	55, 55, 54	33, 30, 31
63182	A540, B24	150-1	145.7	160.0	17.0	56.5	331	53, 50, 52	33, 30, 31

TABLE 5.3-4B
UNIT 2 REACTOR PRESSURE VESSEL HEAD CLOSURE BOLTING MATERIAL PROPERTIES - NUTS AND WASHERS

Heat Number	Material Spec. No.	Bar Number	0.2% Yield Stress (ksi)	Ultimate Tensile Strength (ksi)	Elongation (%)	Reduction in Area (%)	Brinell Hardness Number	Energy at 10°F (ft-lbs)	Lateral Expansion(mils)
85408	SA540, B24	208	147.5	161.0	17.5	54.7	331	54, 54, 52	35, 35, 35
85408	SA540, B24	208-1	149.0	162.0	16.5	51.9	321	50, 50, 49	31, 30, 30
85408	SA540, B24	210	149.0	162.5	17.5	55.5	341	52, 53, 51	33, 34, 30
85408	SA540, B24	210-1	144.7	157.0	18.0	56.2	331	55, 55, 54	36, 36, 33
85408	SA540, B24	214	151.7	165.0	18.0	54.4	321	50, 49, 50	30, 28, 30
85408	SA540, B24	214-1	150.0	164.0	17.5	53.3	321	47, 49, 47	28, 29, 27
85408	SA540, B24	216	147.0	160.0	16.5	54.1	321	50, 50, 51	30, 30, 32
85408	SA540, B24	216-1	150.0	162.5	16.5	53.2	331	52, 52, 53	31, 32, 33
85408	SA540, B24	219	148.0	161.0	17.5	54.4	321	51, 49, 49	30, 28, 28
85408	SA540, B24	219-1	147.0	161.0	17.5	53.0	341	53, 55, 54	30, 34, 33
85408	SA540, B24	222	149.5	163.5	17.0	53.8	341	49, 49, 48	29, 29, 26
85408	SA540, B24	222-1	148.2	162.0	17.5	53.4	341	49, 50, 51	30, 30, 32
85408	SA540, B24	225	148.5	161.0	17.0	53.6	331	52, 50, 52	34, 32, 32
85408	SA540, B24	225-1	150.0	163.0	17.5	54.7	331	51, 50, 50	32, 30, 32

TABLE 5.3-4C
UNIT 1 AND 2 REACTOR PRESSURE VESSEL CLOSURE BOLTING MATERIAL PROPERTIES - HYDRANUTS AND WASHERS

Heat Number	Material	0.2% Yield Stress (ksi) (min, max)	Ultimate Tensile Strength (ksi) (min, max)	Elongation (%) (min, max)	Reduction in Area (%) (min, max)	Brinell Hardness Number (min, max)	Energy at 10°F (ft-lbs) (min, max)	Lateral Expansion(mils) (min, max)
13522	A540, B24	144.75, 151.0	158.0, 165.0	16.0, 17.5	51.7, 54.7	321, 341	47, 54	27, 35
19632	A540, B24	142.0, 150.5	155.0, 162.0	16.0, 17.5	51.9, 55.7	321, 331	47, 52	27, 34
43432	A540, B24	142.5, 150.0	157.0, 164.0	16.5, 18.0	54.6, 57.5	321, 331	49, 55	26, 32
44415	A540, B24	140.0, 151.25	155.0, 164.0	16.5, 18.0	53.6, 57.3	321, 341	49, 56	29, 36
63182	A540, B24	143.25, 149.25	157.0, 162.5	16.5, 18.0	53.0, 58.1	321, 331	48, 56	26, 36
85408	A540, B24	144.75, 151.75	157.0, 165.0	16.5, 18.0	51.9, 56.2	321, 341	47, 55	26, 36

TABLE 5.3-5
REACTOR VESSEL DESIGN PARAMETERS

Design/operating pressure (psig)	2485/2317
Design temperature (°F)	650
Overall height of vessel and closure head, bottom head outside diameter to top of control rod mechanism adapter (ft-in.)	43-6.4 (Unit 1) 43-10 (Unit 2)
Thickness of insulation, minimum (in.)	3
Number of reactor closure head studs	54
Diameter of reactor closure head/studs, minimum shank (in.)	6-13/16
Inside diameter of flange (in.)	167
Outside diameter at shell (in.)	205
Inside diameter at shell (in.)	173
Inlet nozzle inside diameter (in.)	27-1/2
Outlet nozzle inside diameter (in.)	29
Clad thickness, minimum (in.)	1/8
Lower head thickness, minimum (in.)	5-3/8
Vessel belt-line thickness, minimum (in.)	8.63
Closure head thickness (in.)	7 (Unit 1) 6-1/2 (Unit 2)

TABLE 5.3-6A
CHEMICAL COMPOSITION OF UNIT NO. 1 REACTOR VESSEL BELTLINE REGION MATERIAL

Element	Intermediate Shell Plate			Lower Shell Plate			Weld Control No. G1.67[a]
	R1107-1	R1107-2	R1107-3	R1108-1	R1108-2	R1108-3	
C	.22	.22	.25	.22	.21	.22	.16
Mn	1.42	1.33	1.44	1.39	.136	1.40	1.23
P	.010	.010	.007	.008	.006	.008	.008
S	.009	.013	.011	.016	.012	.014	.008
Si	.24	.19	.26	.24	.23	.22	.17
Ni	.65	.64	.68	.64	.59	.64	.17
Cr	.05	.03	.03	.06	.02	.04	.02
Mo	.57	.58	.59	.60	.52	.59	.54
Cu	.06	.06	.05	.08	.05	.07	.04
V	.006	.004	.004	.005	.002	.003	.006
Cb	<.01	<.01	<.01	<.01	<.01	<.01	<.01
Pb	ND	ND	ND	ND	ND	ND	<.001
W	.01	.03	.01	<.01	<.01	<.01	<.01
As	.006	.008	.004	.003	.004	.005	<.001
Sn	.004	.007	.004	.002	.002	.003	.001
Co	.012	.012	.013	.013	.012	.013	.006
N_2	.012	.009	.008	.010	.007	.008	.006
A1	.019	.025	.025	.008	.008	.014	.006
B	<.001	<.001	<.001	<.001	<.001	<.001	<.001
Ti	<.01	<.01	<.01	<.01	<.01	<.01	<.01
Zr	.001	.001	.001	.001	.001	.001	<.001

a) Submerged arc weld - Type B4 Wire Heat No. 88112 and Linde 0091 Flux Lot No. 0145 - used to fabricate all beltline region weld seams.

TABLE 5.3-6B
CHEMICAL COMPOSITION OF UNIT NO. 2 REACTOR VESSEL BELTLINE REGION MATERIAL

Element	Intermediate Shell Plate			Lower Shell Plate			Weld Control No. G3.03[a]	Weld Control No. E3.10[b]
	R3807-1	R3807-2	R3807-3	R3816-1	R3816-2	R3816-3		
C	.21	.22	.22	.23	.23	.22	.16	.088
Mn	1.42	1.40	1.30	1.48	1.48	1.50	1.32	1.33
P	.006	.007	.007	.001	.002	.008	.005	.004
S	.015	.016	.009	.004	.012	.008	.011	.010
Si	.25	.24	.19	.19	.21	.19	.16	.51
Ni	.64	.64	.60	.59	65	.63	.05	.03
Cr	.05	.04	.06	.03	.03	.04	.02	.03
Mo	.60	.59	.58	.49	.50	.52	.54	.54
Cu	.06	.06	.05	.05	.03	.04	.07	.05
V	.002	.003	.002	.003	.003	003	.004	.003
Cb	<.01	<.01	<.01	<.01	<.01	<.01		
Pb	<.001	<.001	<.001	<.001	<.001	<.001		
W	<.01	<.01	<.01	<.01	<.01	<.01		
As	.004	.005	.005	.009	.011	.015		
Sn	.003	.004	.003	.001	.001	.002		
Co	.012	.013	.009	.020	.012	.012		
N_2	.009	.010	.007	.028	.014	.014		
A1	.020	.025	.023	.026	.026	.018		
B	<.001	<.001	<.001	<.001	<.001	<.001		
Ti	<.01	<.01	<.01	<.01	<.01	<.01		
Zr	<.001	<.001	<.001	<.001	<.001	<.001		

a) Submerged arc weld - Type B4 Wire Heat No. 89833 and Linde 0091 Flux Lot No. 1054 - used in seam 101-124 & 101-142A, B, C

b) Submerged arc weld - Type B4 Wire Heat No. 89833 and Linde 124 Flux Lot No. 1061 - used in seam 101-171

TABLE 5.3-7A
UNIT NO. 1 REACTOR VESSEL BELTLINE REGION FRACTURE TOUGHNESS SUMMARY

Plate No. or Welds	Chemistry		Chem. Factor (CF)	Fluence[(a)] Factor (1/4 Thickness)	ΔRT_{NDT}[(c)] (°F)	Initial RT_{NDT} (°F)	Margin[(b)] $2\sqrt{\sigma_I^2 \sigma_\Delta^2}$	Limiting[(d)] ART (°F)
	Cu (Wt %)	Ni (Wt %)						
R1107-1	0.06	0.65	37	0.99	37	10	34	81
R1107-2	0.06	0.64	37	0.99	-	-10	Non Limiting Plate	
R1107-3	0.05	0.68	31	0.99	-	10	Non Limiting Plate	
R1108-1	0.08	0.64	51	0.99	51	0	34	85
R1108-2	0.05	0.59	31	0.99	31	20	31	82
R1108-3	0.07	0.64	44	0.99	-	0	Non Limiting Plate	
Longitudinal	0.04	0.17	40	0.99	-	-70	Non Limiting Plate	
Circumferential	0.04	0.17	40	0.99	-	-70	Non Limiting Plate	

a) Fluence Factor = $f^{(0.28-0.10 \log f)}$
Where: $f = f_{surf}\ e^{-0.24X}$
and: $f_{surf} = 1.59 \times 10^{19} N/Cm^2$, E>1 MeV at 16 EFPY (Westinghouse Design Basis)
X = Distance From Inner (Wetted) Surface (Inches); (Beltline Thickness = 8.63 inches)

b) Error: σ_Δ = 17°F for Base Material and 28°F for Welds (Assume ΔL 0.5 ΔRT_{NDT})
σ_1 = O (Initial RT_{NDT} Values Obtained from "Upper Bound" of Test Results)

c) ΔRT_{NDT} = CF x Fluence Factor

d) Adjusted Reference Temperature (ART) = Initial RT_{NDT} + ΔRT_{NDT} + Margin

TABLE 5.3-7B
UNIT NO. 2 REACTOR VESSEL BELTLINE REGION FRACTURE TOUGHNESS SUMMARY

Plate No. or Welds	Chemistry		Chem. Factor (CF)	Fluence[a] Factor (1/4 Thickness)	ΔRT_{NDT}[c] (°F)	Initial RT_{NDT} (°F)	Margin[b] $2\sqrt{\sigma_I^2 \sigma_\Delta^2}$	Limiting[d] ART (°F)
	Cu (Wt %)	Ni (Wt %)						
R3807-1	0.06	0.64	37	0.99	-	-20	Non Limiting Plate	
R3807-2	0.06	0.64	37	0.99	37	10	34	81
R3807-3	0.05	0.60	31	0.99	-	-20	Non Limiting Plate	
R3816-1	0.05	0.59	31	0.99	-	-30	Non Limiting Plate	
R3816-2	0.03	0.65	20	0.99	-	0	Non Limiting Plate	
R3816-3	0.04	0.63	26	0.99	-	-40	Non Limiting Plate	
Longitudinal	0.07	0.05	38	0.99	-	-50	Non Limiting Weld	
Circumferential	0.05	0.03	29	0.99	-	-60	Non Limiting Weld	

a) Fluence Factor = $f^{(0.28-0.10 \log f)}$
Where: $f = f_{surf}\ e^{-0.24X}$
and: $f_{surf} = 1.59 \times 10^{19} N/Cm^2$, E>1 MeV at 16 EFPY (Westinghouse Design Basis)
X = Distance From Inner (Wetted) Surface (Inches); (Beltline Thickness = 8.63 inches)

b) Error: σ_Δ = 17°F for Base Material and 28°F for Welds (Assume $\Delta \underline{L}$ 0.5 ΔRT_{NDT})
σ_1 = O (Initial RT_{NDT} Values Obtained from "Upper Bound" of Test Results)

c) RT_{NDT} = CF x Fluence Factor

d) Adjusted Reference Temperature (ART) = Initial RT_{NDT} + ΔRT_{NDT} + Margin

TABLE 5.3-8B
UNIT 2 BELTLINE REGION WELD METAL CHARPY V-NOTCH IMPACT DATA

Inter. To Lower Shell Girth Seam Weld Code No. E3.10				Inter. and Lower Shell Long. Seams Weld Code No. G3.03			
Temp (°F)	Energy (Ft-Lb)	Lat. Exp (Mils)	Shear (percent)	Temp. (°F)	Energy (Ft-Lb)	Lat. Exp. (Mils)	Shear (percent)
-80	12	6	0	-80	29	16	5
-80	7	3	0	-80	18	9	0
-80	15	9	0	-80	25	14	5
-40	39	29	20	-40	60	43	30
-40	26	20	10	-40	53	38	25
-40	43	32	20	-40	47	32	25
0	54	39	50	10	105	65	70
0	65	46	50	10	98	62	60
0	55	40	50	10	95	63	60
60	87	61	80	60	120	81	80
60	88	64	80	60	139	82	100
60	86	62	80	60	116	79	80
100	92	74	95	100	152	87	100
100	97	73	95	100	151	85	100
100	94	73	95	100	155	86	100
160	96	76	100	160	168	86	100
160	95	75	100	160	183	87	100
160	96	75	100	160	164	87	100

TABLE 5.3-9A
UNIT 1 CHARPY V-NOTCH IMPACT DATA FOR REACTOR VESSEL
INTERMEDIATE SHELL PLATE CODE R-1107-1

(Transverse Orientation)

Test Temp. (°F)	Energy (FT-LB)	Shear (percent)	Lateral Expansion (MILS)
-40	11	0	6
-40	12	0	8
-40	12	0	7
+10	25	10	17
+10	33	15	23
+10	30	15	19
+40	38	20	26
+40	42	20	29
+40	39	20	26
+60	48	20	34
+60	47	25	40
+60	45	20	32
+70	51	25	37
+70	53	25	38
+70	53	25	39
+100	60	30	47
+100	69	40	52
+100	65	40	50
+160	90	95	68
+160	99	95	73
+160	96	95	72
+212	100	100	72
+212	90	100	69
+212	91	100	70

TABLE 5.3-8A
UNIT 1 BELTLINE REGION WELD METAL CHARPY V-NOTCH IMPACT DATA
WELD CODE NO. G1.67

Test Temp. (°F)	Energy (FT-LB)	Shear (percent)	Lateral Expansion (MILS)
-104	19	9	0
-104	18	10	0
-104	19	10	0
-80	20	10	5
-80	35	20	10
-80	23	12	0
-40	62	37	30
-40	72	43	40
-40	74	44	40
-10	95	54	60
-10	97	58	60
-10	95	55	60
10	124	70	80
10	119	68	80
10	122	73	80
50	131	80	95
50	125	74	90
50	139	82	100
100	149	85	100
100	152	88	100
100	148	82	100

TABLE 5.3-9B
UNIT 2 CHARPY V-NOTCH IMPACT DATA FOR REACTOR VESSEL
INTERMEDIATE SHELL PLATE CODE R-3807-1

(Transverse Orientation)

Test Temp. (°F)	Energy (FT-LB)	Shear (percent)	Lateral Expansion (MILS)
-40	7	0	2
-40	13	0	6
-40	11	0	5
+0	44	20	31
+0	52	25	35
+0	33	15	24
+40	62	30	45
+40	68	30	47
+40	65	30	45
+100	92	60	60
+100	90	60	63
+100	81	40	50
+160	116	100	69
+160	108	100	72
+160	109	100	74
+212	103	100	76
+212	111	100	77
+212	99	100	70

TABLE 5.3-10A
UNIT 1 CHARPY V-NOTCH IMPACT DATA FOR REACTOR VESSEL
INTERMEDIATE SHELL PLATE CODE R-1107-2

(Transverse Orientation)

Test Temp. (°F)	Energy (FT-LB)	Shear (percent)	Lateral Expansion (MILS)
-40	9	0	5
-40	11	0	6
-40	15	0	9
+10	31	15	22
+10	38	20	26
+10	38	20	25
+40	50	25	34
+40	41	20	26
+40	54	30	37
+50	65	35	42
+50	60	30	40
+50	52	25	37
+60	70	35	47
+60	51	25	35
+60	60	30	41
+100	72	50	54
+100	69	50	50
+100	77	60	58
+160	95	95	67
+160	98	95	70
+160	92	95	66
+212	105	100	77
+212	100	100	70
+212	104	100	75

TABLE 5.3-10B
UNIT 2 CHARPY V-NOTCH IMPACT DATA FOR REACTOR VESSEL
INTERMEDIATE SHELL PLATE CODE R-3807-2

(Transverse Orientation)

Test Temp. (°F)	Energy (FT-LB)	Shear (percent)	Lateral Expansion (MILS)
-20	22	5	16
-20	21	0	14
-20	19	0	13
+40	43	20	31
+40	40	20	28
+40	55	25	38
+60	71	40	48
+60	48	20	36
+60	64	30	43
+70	65	50	49
+70	63	40	44
+70	65	40	46
+100	79	70	55
+100	78	70	52
+100	74	60	49
+160	99	95	69
+160	96	90	64
+160	103	95	72
+212	98	100	66
+212	104	100	67
+212	100	100	66

TABLE 5.3-11A
UNIT 1 CHARPY V-NOTCH IMPACT DATA FOR REACTOR VESSEL
INTERMEDIATE SHELL PLATE CODE R-1107-3

(Transverse Orientation)

Test Temp. (°F)	Energy (FT-LB)	Shear (percent)	Lateral Expansion (MILS)
+0	22	0	17
+0	19	0	16
+0	16	0	12
+40	42	20	27
+40	34	15	24
+40	39	15	26
+60	40	20	30
+60	54	30	41
+60	51	30	36
+70	53	25	37
+70	51	25	37
+70	53	30	36
+100	65	30	45
+100	70	40	51
+100	65	35	48
+160	92	95	72
+160	86	90	64
+160	90	95	71
+212	87	100	64
+212	92	100	70
+212	85	100	66

TABLE 5.3-11B
UNIT 2 CHARPY V-NOTCH IMPACT DATA FOR REACTOR VESSEL
INTERMEDIATE SHELL PLATE CODE R-3807-3

(Transverse Orientation)

Test Temp. (°F)	Energy (FT-LB)	Shear (percent)	Lateral Expansion (MILS)
-40	16	0	8
-40	16	0	8
-40	14	0	7
+0	28	10	18
+0	28	10	18
+0	34	15	24
+40	50	25	36
+40	51	25	35
+40	50	25	36
+100	85	80	59
+100	78	80	53
+100	61	50	46
+160	106	100	70
+160	102	100	71
+160	94	100	64
+212	104	100	71
+212	104	100	70
+212	106	100	72

TABLE 5.3-12A
UNIT 1 CHARPY V-NOTCH IMPACT DATA FOR REACTOR VESSEL LOWER SHELL PLATE CODE R-1108-1

(Transverse Orientation)

Test Temp. (°F)	Energy (FT-LB)	Shear (percent)	Lateral Expansion (MILS)
-40	16	0	10
-40	18	0	12
-40	16	0	11
+0	32	15	24
+0	28	10	21
+0	31	15	22
+40	43	20	29
+40	35	15	27
+40	37	15	24
+50	53	25	36
+50	46	20	32
+50	45	20	35
+60	52	25	37
+60	61	30	43
+60	60	30	41
+100	60	70	49
+100	74	80	57
+100	66	70	51
+160	90	100	66
+160	76	90	59
+160	86	100	62
+212	83	100	62
+212	81	100	62
+212	86	100	64

TABLE 5.3-12B
UNIT 2 CHARPY V-NOTCH IMPACT DATA FOR REACTOR VESSEL LOWER SHELL PLATE CODE R-3816-1

(Transverse Orientation)

Test Temp. (°F)	Energy (FT-LB)	Shear (percent)	Lateral Expansion (MILS)
-40	14	0	7
-40	21	5	12
-40	22	5	14
+0	52	25	36
+0	42	20	28
+0	43	20	28
+30	54	20	37
+30	61	25	42
+30	56	25	40
+60	70	40	47
+60	83	40	51
+60	75	40	49
+100	107	90	66
+100	98	90	67
+100	105	90	70
+160	103	100	70
+160	109	100	73
+160	110	100	71

TABLE 5.3-13A
UNIT 1 CHARPY V-NOTCH IMPACT DATA FOR REACTOR VESSEL LOWER SHELL PLATE CODE R-1108-2

(Transverse Orientation)

Test Temp. (°F)	Energy (FT-LB)	Shear (percent)	Lateral Expansion (MILS)
-40	9	0	4
-40	8	0	4
-40	9	0	5
+0	24	10	19
+0	24	10	19
+0	23	10	18
+30	26	15	19
+30	29	15	20
+30	29	15	22
+70	53	30	40
+70	48	25	38
+70	56	30	42
+80	51	30	38
+80	56	30	42
+80	55	30	42
+100	53	30	42
+100	57	30	44
+100	62	40	49
+160	78	95	58
+160	76	95	54
+160	73	95	53
+212	78	100	55
+212	79	100	55
+212	77	100	54

TABLE 5.3-13B
UNIT 2 CHARPY V-NOTCH IMPACT DATA FOR REACTOR VESSEL LOWER SHELL PLATE CODE R-3816-2

(Transverse Orientation)

Test Temp. (°F)	Energy (FT-LB)	Shear (percent)	Lateral Expansion (MILS)
-40	18	0	9
-40	15	0	8
-40	20	0	10
+0	31	10	20
+0	23	5	17
+0	28	10	21
+30	42	20	33
+30	48	20	38
+30	38	20	24
+50	46	20	35
+50	54	25	42
+50	55	25	39
+60	73	35	47
+60	59	30	39
+60	66	35	41
+100	85	50	61
+100	88	60	61
+100	86	60	58
+160	98	100	67
+160	107	100	71
+160	104	100	68
+212	107	100	68
+212	106	100	68
+212	105	100	68

TABLE 5.3-14A
UNIT 1 CHARPY V-NOTCH IMPACT DATA FOR REACTOR VESSEL LOWER SHELL PLATE CODE R-1108-3

(Transverse Orientation)

Test Temp. (°F)	Energy (FT-LB)	Shear (percent)	Lateral Expansion (MILS)
-40	7	0	5
-40	15	0	11
-40	10	0	7
+0	27	10	19
+0	29	10	20
+0	34	15	23
+30	43	20	22
+30	38	15	20
+30	53	25	35
+50	48	25	35
+50	47	20	34
+50	63	30	42
+60	50	25	36
+60	63	30	47
+60	61	30	45
+100	82	50	57
+100	72	40	53
+100	70	40	49
+160	93	90	62
+160	91	90	60
+160	96	90	64
+212	102	100	69
+212	97	100	68
+212	96	100	65

TABLE 5.3-14B
UNIT 2 CHARPY V-NOTCH IMPACT DATA FOR REACTOR VESSEL LOWER SHELL PLATE CODE R-3816-3

(Transverse Orientation)

Test Temp. (°F)	Energy (FT-LB)	Shear (percent)	Lateral Expansion (MILS)
-80	7	0	5
-80	11	0	7
-80	13	0	7
-40	32	10	17
-40	25	5	14
-40	22	5	12
+0	39	15	24
+0	38	15	26
+0	44	20	29
+20	58	30	41
+20	52	25	36
+20	59	30	41
+60	77	35	47
+60	89	40	52
+60	84	40	54
+100	102	90	64
+100	94	90	65
+100	94	100	61
+160	109	100	71
+160	105	100	65
+160	103	100	69
+212	105	100	63
+212	108	100	67
+212	111	100	68

TABLE 5.3-15A
UNIT 1 REACTOR VESSEL NON-BELTLINE WELD METAL TOUGHNESS PROPERTIES

Weld Location	Weld Seam No.	Weld Mat'l Code No.	T_{NDT} °F	50 Ft-Lb/35 Mil Temp. °F	RT_{NDT} °F
Vessel Flange to Nozzle Shell	101-121	G 1.71	-50	< 10	-50
Vessel Flange to Nozzle Shell	101-121	G 2.08	-60	< 0	-60
Nozzle Shell Long. Seams	101-122 A,B and C	G 1.59	-50	< 10	-50
Inlet Nozzle to Nozzle Shell	105-121 A and C	G 3.09	-70	< -10	-70
Inlet Nozzle to Nozzle Shell	105-121 B and D	G 2.28	-70	< -10	-70
Inlet Nozzle to Nozzle Shell	105-121 D	G 2.23	-60	< 0	-60
Outlet Nozzle to Nozzle Shell	107-121 A and C	G 2.28	-70	< -10	-70
Outlet Nozzle to Nozzle Shell	107-121 B and D	G 3.09	-70	< -10	-70
Nozzle Shell to Inter. Shell	103-121	G 2.12	-60	< 0	-60
Lower Shell to Bottom Head Torus	101-141	E 2.09	-70	< -10	-70
Bottom Head Torus Long. Seams	101-154 A,B,C and D	A 2.19	-70	< -10	-70
Bottom Head Torus to Bottom Head Dome	102-151	G 3.09	-70	< -10	-70

TABLE 5.3-15B
UNIT 2 REACTOR VESSEL NON-BELTLINE WELD METAL TOUGHNESS PROPERTIES

Weld Location	Weld Seam No.	Weld Mat'l Code No.	T_{NDT} °F	50 Ft-Lb/35 Mil Temp. °F	RT_{NDT} °F
Closure Head Dome to Closure Head Torus	103-101	E 3.08	-80	< -20	-80
Closure Head Torus Long. Seams	101-104 A,B,C and D	A 2.16	-80	< -20	-80
Closure Head Torus to Closure Head Flange	101-101	E 3.08	-80	< 20	-80
Vessel Flange to Nozzle Shell	101-121	E 2.10	-80	< 30	-30
Vessel Flange to Nozzle Shell	101-121	E 2.09	-70	< -10	-70
Vessel Flange to Nozzle Shell	101-121	E 2.17	-50	< 10	-50
Nozzle Shell Long. Seams	101-122 A,B and C	G 3.07	-80	< -20	-80
Inlet Nozzle to Nozzle Shell	105-121 A and C	E 3.08	-80	< -20	-80
Inlet Nozzle to Nozzle Shell	105-121 B and D	E 3.02	-70	< -10	-70
Outlet Nozzle to Nozzle Shell	107-121 A and C	E 3.02	-70	< -10	-70
Outlet Nozzle to Nozzle Shell	107-121 B and D	E 3.08	-80	< -20	-80
Nozzle Shell to Inter. Shell	103-121	E 2.13	-80	< -20	-80
Lower Shell to Bottom Head Torus	101-141	E 4.05	-80	< 0	-60
Bottom Head Torus Long. Seams	101-154 A,B,C and D	A 2.33	-50	< 10	-50
Bottom Head Torus to Bottom Head Dome	102-151	E 4.01	-80	< -10	-70

TABLE 5.3-16A
UNIT 1 STEAM GENERATOR AND PRESSURIZER BASE METAL FRACTURE TOUGHNESS DATA

Component	Component Part	Test Number	2NB Drop Wt °F	T_{NDT} °F	°F for 50 ft lb/35 MLE	RT_{NDT} °F
SG 1 CH2	Channel Head	EM 4636	70	60	< 120	60
	Tube Sheet	EM 4591	70	60	< 120	60
SG 2 CH2	Channel Head	EM 4648	70	60	< 120	60
	Tube Sheet	EM 4592	70	60	< 120	60
SG 3 CH2	Channel Head	EM 4649	70	60	< 120	60
	Tube Sheet	EM 4602	70	60	< 120	60
SG 4 CH2	Channel Head	EM 4650	70	60	< 120	60
	Tube Sheet	EM 4610	70	60	< 120	60
Pressurizer	Lower Head	4902-1	70	60	< 120	60
	Surge Nozzle	4742-1	70	60	< 120	60
	Upper Head	4896-1	70	60	< 120	60
	Manway Nozzle	4708-4	70	60	< 120	60
	Safety Nozzle	4749-12	70	60	< 120	60
	Safety Nozzle	4749-4	70	60	< 120	60
	Safety Nozzle	4749-11	70	60	< 120	60
	Relief Nozzle	4749-16	70	60	< 120	60
	Spray Nozzle	4743-4	70	60	< 120	60
	Manway Cover	5775	70	60	< 120	60
	Shell Barrel	4906	70	60	< 120	60
	Shell Barrel	4905	70	60	< 120	60
	Shell Barrel	4926	70	60	< 120	60
	Shell Barrel	4921	70	60	< 120	60

TABLE 5.3-16B
UNIT 2 STEAM GENERATOR AND PRESSURIZER BASE METAL FRACTURE TOUGHNESS DATA

Component	Component Part	Test Number	2NB Drop Wt °F	T_{NDT} °F	°F for 50 ft lb/35 MLE	RT_{NDT} °F
SG 2211	Channel Head	5012	70	60	< 120	60
	Tube Sheet	4338	70	60	< 120	60
SG 2212	Channel Head	5219	70	60	< 120	60
	Tube Sheet	4337	70	60	< 120	60
SG 2213	Channel Head	5263	70	60	< 120	60
	Tube Sheet	4685	70	60	< 120	60
SG 2214	Channel Head	5013	70	60	< 120	60
	Tube Sheet	4882	70	60	< 120	60
Pressurizer	Lower Head	4985	70	60	< 120	60
	Surge Nozzle	5672	70	60	< 120	60
	Upper Head	5743	70	60	< 120	60
	Manway Nozzle	5653	70	60	< 120	60
	Safety Nozzle	5514-4	70	60	< 120	60
	Safety Nozzle	5418-9	70	60	< 120	60
	Safety Nozzle	5418-11	70	60	< 120	60
	Relief Nozzle	5418-10	70	60	< 120	60
	Spray Nozzle	5697	70	60	< 120	60
	Manway Cover	6467	70	60	< 120	60
	Shell Barrel	5828	70	60	< 120	60
	Shell Barrel	5829	70	60	< 120	60
	Shell Barrel	5839	70	60	< 120	60
	Shell Barrel	5867	70	60	< 120	60

TABLE 5.3-17A
UNIT 1 STEAM GENERATOR AND PRESSURIZER WELD METAL FRACTURE TOUGHNESS DATA

Weld Type	Test Number Electrode	Test Number Flux	2NB Drop Wt °F	T_{NDT} °F	°F for 50 ft lb/35 MLE	RT_{NDT} °F
SMAW	5167	---	20	10	< 70	10
	5199	---	20	10	< 70	10
	5200	---	20	10	< 70	10
	5299	---	20	10	< 70	10
	5300	---	20	10	< 70	10
	5301	---	20	10	< 70	10
	5315	---	20	10	< 70	10
	5318	---	20	10	< 70	10
	5319	---	20	10	< 70	10
	5429	---	20	10	< 70	10
	5431	---	20	10	< 70	10
	5444	---	20	10	< 70	10
	5447	---	20	10	< 70	10
	5450	---	20	10	< 70	10
	5451	---	20	10	< 70	10
	5455	---	20	10	< 70	10
SAW	4110	5330	20	10	< 70	10
	4109	5330	20	10	< 70	10
	4109	5126	20	10	< 70	10
	5164	5511	20	10	< 70	10
	5478	5511	20	10	< 70	10
	5477	6033	20	10	< 70	10

TABLE 5.3-17A
UNIT 1 STEAM GENERATOR AND PRESSURIZER WELD METAL FRACTURE TOUGHNESS DATA

SMAW[(a)]	3071	---	20	10	<70	10
	5310	---	20	10	<70	10
SAW[a]	128734.1	128734.1	20	10	<70	10

a) These values are for the Unit 1 Model Delta 76 Steam Generator. The values for the original installation steam generator have been maintained in this Table for historical information.

TABLE 5.3-17B
COMPANCHE PEAK UNIT 2 STEAM GENERATOR AND PRESSURIZER WELD METAL FRACTURE TOUGHNESS DATA

(Sheet 1 of 2)

Component	Test Number Electrode	Test Number Flux	2NB Drop Wt °F	T_{NDT} °F	°F for 50 ft lb/35 MLE	RT_{NDT} °F
SMAW	5458	---	20	10	< 70	10
	6026	---	20	10	< 70	10
	6027	---	20	10	< 70	10
	6041	---	20	10	< 70	10
	6049	---	20	10	< 70	10
	6164	---	20	10	< 70	10
	6165	---	20	10	< 70	10
	6182	---	20	10	< 70	10
	6193	---	20	10	< 70	10
	6787	---	20	10	< 70	10
	6790	---	20	10	< 70	10
	7386	---	20	10	< 70	10
	7404	---	20	10	< 70	10
	7417	---	20	10	< 70	10
	7643	---	20	10	< 70	10
	7960	---	20	10	< 70	10
	7967	---	20	10	< 70	10
	7969	---	20	10	< 70	10

TABLE 5.3-17B
COMPANCHE PEAK UNIT 2 STEAM GENERATOR AND PRESSURIZER WELD METAL FRACTURE TOUGHNESS DATA

(Sheet 2 of 2)

Component	Test Number Electrode	Test Number Flux	2NB Drop Wt °F	T_{NDT} °F	°F for 50 ft lb/35 MLE	RT_{NDT} °F
	7973	---	20	10	< 70	10
	7978	---	20	10	< 70	10
	8297	---	20	10	< 70	10
	8303	---	20	10	< 70	10
	8308	---	20	10	< 70	10
	7961	---	20	10	< 70	10
	7977	---	20	10	< 70	10
	3415	---	20	10	< 70	10
	4514	---	20	10	< 70	10
SAW	4109	5330	20	10	< 70	10
	4110	5330	20	10	< 70	10
	5478	5511	20	10	< 70	10
	5477	6033	20	10	< 70	10
	6180	6033	20	10	< 70	10
	6181	6185	20	10	< 70	10
	7653	6769	20	10	< 70	10
	6330	6769	20	10	< 70	10
	8301	6769	20	10	< 70	10

5.4 COMPONENT AND SUBSYSTEM DESIGN

5.4.1 REACTOR COOLANT PUMPS

5.4.1.1 Design Bases

The reactor coolant pump ensures an adequate core cooling flow rate and hence sufficient heat transfer, to maintain a departure from nucleate boiling ratio (DNBR) greater than the limit value within the parameters of operation. The required net positive suction head is by conservative pump design always less than that available by system design and operation.

Sufficient pump rotation inertia is provided by a fly wheel, in conjunction with the impeller and motor assembly, to provide adequate flow during coastdown. This flow following an assumed loss of pump power aids in the development of a thermal gradient for initiation of natural circulation while providing the core with adequate cooling.

The reactor coolant pump motor is tested, without mechanical damage, at overspeeds up to and including 125 percent of normal speed. The integrity of the flywheel during a loss of coolant accident (LOCA) is demonstrated in Reference [1] which is undergoing generic review by the NRC staff.

Ongoing steam/water tests being planned jointly by Westinghouse, Framatone, and the French Atomic Energy Commission (CEA) are described in Section 1.5. The ultimate use of the data from these tests will be to develop an empirical two phase flow pump performance model. It is expected that this new model will confirm that the present pump model conservatively predicts performance in all LOCA conditions and thus increases the safety margin available in Emergency Core Cooling System (ECCS) and reactor coolant pump overspeed analyses.

The reactor coolant pump is shown in Figure 5.4-1. The reactor coolant pump design parameters are given in Table 5.4-1.

Code and material requirements are provided in Section 5.2.

5.4.1.2 Design Description

The reactor coolant pump is a vertical, single stage, centrifugal, shaft seal pump designed to pump large volumes of main coolant at high temperatures and pressures.

The pump consists of three areas from bottom to top. They are the hydraulics, the shaft seals, and the motor.

1. The hydraulic section consists of an impeller, diffuser, casing, thermal barrier, heat exchanger, lower radial bearing, main flange, motor stand, and pump shaft.

2. The shaft seal section consists of three devices. They are the number 1 controlled leakage, film riding face seal and the number 2 and 3 rubbing face seals. These seals are contained within the main flange and seal housing.

3. The motor section consists of a vertical solid shaft, squirrel cage induction type motor, and oil lubricated double Kingsbury type thrust bearing, two oil lubricated radial bearings, and a flywheel.

Attached to the bottom of the pump shaft is the impeller. The reactor coolant is drawn up through the impeller, discharged through passages in the diffuser, and out through the discharge nozzle in the side of the casing. Above the impeller is a thermal barrier heat exchanger which limits heat transfer between hot system water and seal injection water. Component cooling water is supplied to the thermal barrier heat exchanger.

High pressure seal injection water is introduced through the thermal barrier wall. A portion of this water flows through the radial bearing and the seals; the remainder flows down the shaft through the thermal barrier where it acts as a buffer to prevent system water from entering the radial bearing and seal section of the unit. The thermal barrier heat exchanger provides a means of cooling system water to an acceptable level in the event that seal injection flow is lost. The water lubricated journal type pump bearing, mounted above the thermal barrier heat exchanger, has a self-aligning spherical seat.

The reactor coolant pump motor bearings are of conventional design. The radial bearings are the segmented pad type, and the thrust bearings are tilting pad Kingsbury bearings. All are oil lubricated. The lower radial bearing and the thrust bearings are submerged in oil, and the upper radial bearing is oil fed from a viscosity pump integral with the thrust runner. Component cooling water is supplied to the two oil coolers on the pump motor.

The motor is a water/air cooled, Class B thermalastic epoxy insulated, squirrel cage induction motor. The rotor and stator are of standard construction and are cooled by air. Six resistance temperature detectors are located throughout the stator to sense the winding temperature. The top of the motor consists of a flywheel and an anti-reverse rotation device.

The internal parts of the motor are cooled by air. Integral vanes on each end of the rotor draw air in through cooling slots in the motor frame. This air passes through the motor with particular emphasis on the stator end turns. It is then routed to the external water/air heat exchangers, which are supplied with component cooling water.

Each motor has two such coolers, mounted diametrically opposed to each other. In passing through the coolers the air is cooled to below 122°F so that minimum heat is rejected to the Containment from the motors.

Each of the reactor coolant pumps is equipped with two vibration pickups. The shaft monitoring system is mounted near the coupling hub, in a horizontal plane to pickup radial vibrations of the pump shaft. The frame monitoring system is similar to the shaft monitoring system and is mounted at the top of the motor support. Signals from all the reactor coolant pumps are sent to a Control Room Monitoring Cabinet. The signals may be read on a vibration meter which shows the amplitude of pump shaft and frame vibration.

All parts of the pump in contact with the reactor coolant are austenitic stainless steel except for seals, bearings and special parts.

A removable shaft segment, the spool piece, is located between the motor coupling flange and the pump coupling flange; the spool piece allows removal of the pump seals with the motor in

place. The pump shaft, seal housing, thermal barrier, main flange and motor stand can be removed from the casing without disturbing the reactor coolant piping. The flywheel is available for inspection by removing the cover.

5.4.1.3 Design Evaluation

5.4.1.3.1 Pump Performance

The reactor coolant pumps are sized to deliver flow at rates which equal or exceed the required flow rates. Initial Reactor Coolant System (RCS) tests confirm the total delivery capability. Thus, assurance of adequate forced circulation coolant flow is provided prior to initial plant operation.

The performance characteristic, shown in Figure 5.4-2, is common to all of the fixed speed mixed flow pumps, and the “knee” at about 45 percent design flow introduces no operational restrictions, since the pumps operate at full speed.

The Reactor Trip System ensures that pump operation is within the assumptions used for loss of coolant flow analyses, which also assures that adequate core cooling is provided to permit an orderly reduction in power if flow from a reactor coolant pump is lost during operation.

An extensive test program has been conducted for several years to develop the controlled leakage shaft seal for pressurized water reactor applications. Long term tests were conducted on less than full scale prototype seals as well as on full size seals. Operating plants continue to demonstrate the satisfactory performance of the controlled leakage shaft seal pump design.

The support of the stationary member of the number 1 seal (“seal ring”) is such as to allow large deflections, both axial and tilting, while still maintaining its controlled gap relative to the seal runner. Even if all the graphite were removed from the pump bearing, the shaft could not deflect far enough to cause opening of the controlled leakage gap. The “spring-rate” of the hydraulic forces associated with the maintenance of the gap is high enough to ensure that the ring follows the runner under very rapid shaft deflections.

Testing of pumps with the number 1 seal entirely removed (full system pressure on the number 2 seal) shows that relatively small leakage rates would be maintained for long periods of time; even if the number 1 seal fails entirely the number 2 seal would maintain these small leakage rates. The plant operator is warned of number 1 seal damage by the increase in number 1 seal leakoff. Following warning of excessive seal leakage conditions, the plant operator should secure the pumps then close the number 1 seal leakoff valve to the pump, to reduce possible damage. Gross leakage from the pump does not occur if the proper operator action is taken subsequent to warning of excessive seal leakage conditions.

Seal Injection from the Chemical and Volume Control System (CVCS), to the Reactor Coolant Pumps is supplied with a bypass valve which may be opened if pump bearing temperature or seal water inlet temperature limits are exceeded and RCS pressure is greater than 100 psig. Opening the bypass valve ensures adequate cooling to the lower bearing when seal leakoff flow is insufficient to cool the radial bearing. Continued pump operation with the seal bypass line open, although not recommended, will not result in damage to the number 1 seal, nor will the performance of the number 2 and number 3 seals be affected.

The effect of loss of offsite power on the pump itself is to cause a temporary stoppage in the supply of injection flow to the pump seals and also of the cooling water for seal and bearing cooling. The emergency diesel generators are started automatically due to loss of offsite power so that component cooling flow is automatically restored. Seal water injection flow is subsequently restored by a charging pump automatically restarting on diesel power.

Consequences of the loss of component cooling water flow to RCS pumps are discussed in Section 9.2.2.

5.4.1.3.2 Coastdown Capability

It is important to reactor operation that the reactor coolant continues to flow for a short time after reactor trip. In order to provide this flow in a station blackout condition, each reactor coolant pump is provided with a flywheel. Thus, the rotating inertia of the pump, motor and flywheel is employed during the coastdown period to continue the reactor coolant flow. The coastdown flow transients are provided in the figures in Section 15.3.

The pump/motor system is designed for the Safe Shutdown Earthquake at the site and the integrity of the bearings is described in Section 5.4.1.3.3. Hence, it is concluded that the coastdown capability of the pumps is maintained even under the most adverse case of a blackout coincident with the Safe Shutdown Earthquake. Core flow transients and figures are provided in Sections 15.3.1 and 15.4.4.

5.4.1.3.3 Bearing Integrity

The design requirements for the reactor coolant pump bearings are primarily aimed at ensuring a long life with negligible wear, so as to give accurate alignment and smooth operation over long periods of time. The surface-bearing stresses are held at a very low value, and even under the most severe seismic transients do not begin to approach loads which cannot be adequately carried for short periods of time.

Because there are no established criteria for short time stress related failures in such bearings, it is not possible to make a meaningful quantification of such parameters as margins to failure, safety factors, etc. A qualitative analysis of the bearing design, embodying such considerations, gives assurance of the adequacy of the bearing to operate without failure.

Low oil levels in the lube oil sumps signal an alarm in the Control Room and require shutting down of the pump. Each motor bearing contains embedded temperature detectors, and so initiation of failure, separate from loss of oil, is indicated and alarmed in the Control Room as a high bearing temperature. This, again, requires pump shutdown. If these indications are ignored, and the bearing proceeded to failure, the low melting point of Babbitt metal on the pad surfaces ensures that sudden seizure of the shaft will not occur. In this event the motor continues to operate, as it has sufficient reserve capacity to drive the pump under such conditions. However, the high torque required to drive the pump will require high current which will lead to the motor being shutdown by the electrical protection systems.

5.4.1.3.4 Locked Rotor

It may be hypothesized that the pump impeller might severely rub on a stationary member and then seize. Analysis has shown that under such conditions, assuming instantaneous seizure of

the impeller, the pump shaft fails in torsion just below the coupling to the motor, disengaging the flywheel and motor from the shaft. This constitutes a loss of coolant flow in the loop. Following such a postulated seizure, the motor continues to run without any overspeed, and the flywheel maintains its integrity, as it is still supported on a shaft with two bearings. Flow transients are provided in the figures in Section 15.3.3 for the assumed locked rotor.

There are no other credible sources of shaft seizure other than impeller rubs. Any seizure of the pump bearing is precluded by graphite in the bearing. Any seizure in the seals results in a shearing of the antirotation pin in the seal ring. The motor has adequate power to continue pump operation even after the above occurrences. Indications of pump malfunction in these conditions are initially by high temperature signals from the bearing water temperature detector, and excessive number 1 seal leakoff indications respectively. Following these signals, pump vibration levels are checked. Excessive vibration indicates mechanical trouble and the pump is shutdown for investigation.

5.4.1.3.5 Critical Speed

The reactor coolant pump shaft is designed so that its operating speed is below its first critical speed. This shaft design, even under the most severe postulated transient, gives low values of actual stress.

5.4.1.3.6 Missile Generation

Precautionary measures taken to preclude missile formation from primary coolant pump components assure that the pumps will not produce missiles under any anticipated accident condition. Each component of the primary pump motors has been analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller because the small fragments that might be ejected would be contained by the heavy casing. Further discussion and analysis of missile generation is contained in Reference [1].

5.4.1.3.7 Pump Cavitation

The minimum net positive suction head required by the reactor coolant pump at running speed is approximately a 192 foot head (approximately 85 pounds per square inch (psi)). Proper operation of the controlled leakage seal is assured by requiring a minimum differential pressure of 200 psi across the seal. The corresponding RCS pressure is approximately 325 psi during a normal fill and vent evolution. During a vacuum fill evolution, the RCS pressure requirement is 250 psid across the seal. At this pressure the net positive suction head requirement is exceeded and the pump can be successfully operated.

5.4.1.3.8 Pump Overspeed Considerations

For turbine trips actuated by either the Reactor Trip System or the Turbine Protection System (with the exception of turbine trips caused by low lube oil pressure, thrust bearing, and local manual trip), the generator and reactor coolant pumps are maintained connected to the external network for 30 seconds to prevent any pump overspeed condition.

An electrical fault requiring immediate trip of the generator (with resulting turbine trip) could result in an overspeed condition. However, the Turbine Control System and the turbine intercept valves

limit the overspeed to less than 120 percent. As additional back-up, the Turbine Protection System has redundant and diverse overspeed protection systems, usually set at about 110 percent (of turbine speed). In case a generator trip de-energizes the pump buses, the reactor coolant pump motors will be transferred to offsite power within 6 to 10 cycles. Further discussion of pump overspeed considerations is contained in Reference [1].

5.4.1.3.9 Anti-Reverse Rotation Device

Each of the reactor coolant pumps is provided with an anti-reverse rotation device in the motor. This anti-reverse mechanism consists of five pawls mounted on the outside diameter of the flywheel, a serrated ratchet plate mounted on the motor frame, a spring return for the ratchet plate, and two shock absorbers.

After the motor has slowed and come to a stop, the dropped pawls engage the ratchet plate and, as the motor tends to rotate in the opposite direction, the ratchet plate also rotates until it is stopped by the shock absorbers. The rotor remains in this position until the motor is energized again. When the motor is started, the ratchet plate is returned to its original position by the spring return.

As the motor begins to rotate, the pawls drag over the ratchet plate. When the motor reaches sufficient speed, the pawls are bounced into an elevated position and are held in that position by friction resulting from centrifugal forces acting upon the pawls. Considerable shop testing and plant experience with the design of these pawls have shown high reliability of operation.

5.4.1.3.10 Shaft Seal Leakage

Leakage along the reactor coolant pump shaft is controlled by three shaft seals arranged in series such that reactor coolant leakage to the Containment is essentially zero. Charging flow is directed to each reactor coolant pump via a seal water injection filter (See Table 9.3-7). It enters the pumps through a connection on the thermal barrier flange and is directed down to a point between the pump shaft bearing and the thermal barrier cooling coils. Here the flow enters the shaft annulus; a portion flows down through the thermal barrier labyrinth, past the cooling coils and into the RCS; the remainder flows up the pump shaft annulus cooling the lower shaft bearing. This flow provides a backpressure on the number 1 seal and a controlled flow through the seal. During normal operation of the pump and seal, most of the flow leaves the pump through the number 1 seal leakoff line. Minor flow passes through the number 2 seal and leakoff line. A back flush injection of 800 cubic centimeters per hour (cc/hr) from a standpipe flows into the number 3 seal between its “double dam” seal area. At this point the flow divides with half flushing through one side of the seal and out the number 2 seal leakoff while the remaining half flushes through the other side and out the number 3 leakoff. This arrangement assures essentially zero leakage of reactor coolant or trapped gases from the pump.

5.4.1.3.11 Seal Discharge Piping

Discharge pressure from the number 1 seal is reduced to that of the volume control tank. Water from each pump number 1 seal is piped to a common manifold, and through the seal water return filter and through the seal water heat exchanger where the temperature is reduced to that of the volume control tank. The number 2 leakoff lines dump number 2 seal leakage to the reactor coolant drain tank; the number 3 leakoff lines discharge number 3 seal leakage to the

Containment sump. A description of the RCS pump seal flow is given in Section 9.3.4.1.2.1. Details are shown on Figure 9.3-10 sheet 1.

5.4.1.4 Tests and Inspections

The reactor coolant pumps can be inspected in accordance with the American Society of Mechanical Engineers (ASME) Code, Section XI, for inservice inspection of nuclear reactor coolant systems. Any full penetration welds in the pressure boundary are prepared with a smooth surface transition between weld metal and parent metal for radiographic inspection.

The pump casing is cast in one piece, eliminating welds in the casing. Support feet are cast integral with the casing to eliminate a weld region.

The design enables disassembly and removal of the pump internals for usual access to the internal surface of the pump casing.

The reactor coolant pump quality assurance program is given in Table 5.4-2.

5.4.1.5 Pump Flywheels

The integrity of the reactor coolant pump flywheel is assured on the basis of the following design and quality assurance procedures.

5.4.1.5.1 Design Basis

The calculated stresses at operating speed are based on stresses due to centrifugal forces. The stress resulting from the interference fit of the flywheel on the shaft is less than 2000 psi at zero speed, but this stress becomes zero at approximately 600 revolutions per minute (rpm) because of radial expansion of the hub. The primary coolant pumps run at approximately 1190 rpm and may operate briefly at overspeeds up to 109 percent (1295 rpm) during loss of outside load. For conservatism, however, 125 percent of operating speed was selected as the design speed for the primary coolant pumps. The flywheels are given a preoperational test of 125 percent of the maximum synchronous speed of the motor.

5.4.1.5.2 Fabrication and Inspection

The flywheel consists of two thick plates bolted together. The flywheel material is produced by a process that minimizes flaws in the material and improves its fracture toughness properties, such as vacuum degassing, vacuum melting, or electroslag remelting. Each plate is fabricated from SA-533, Grade B, Class 1 steel. Supplier certification reports are available for all plates and demonstrate the acceptability of the flywheel material on the basis of the requirements of Regulatory Guide 1.14.

Flywheel blanks are flame-cut from the SA-533, Grade B, Class 1 plates with at least 1/2 inch of stock left on the outer and bore radii for machining to final dimensions. The finished machined bores, keyways, and drilled holes are subjected to magnetic particle or liquid penetrant examinations. The finished flywheels are subjected to 100 percent volumetric ultrasonic inspection per paragraphs NB-2532.1 and NB-2532.2 of the ASME Code, Section III.

The reactor coolant pump motors are designed such that the flywheel is available by removing the cover to provide access to allow an inservice inspection program in accordance with requirements of Section XI of the ASME code. The inservice inspection program is in accordance with Technical Specification 5.5.7.

5.4.1.5.3 Acceptance Criteria and Compliance with Regulatory Guide 1.14

The reactor coolant pump motor flywheel shall conform to the following material acceptance.

1. The nil-ductility transition temperature (NDTT) of the flywheel material shall be obtained by two drop weight tests (DWT) which will exhibit “no-break” performance at 20°F in accordance with ASTM-E-208. The above drop weight tests demonstrate that the NDTT of the flywheel material is no higher than 10°F.

2. A minimum of three Charpy V-notch impact specimens from each plate shall be tested at ambient (70°F) temperature in accordance with the specification ASTM-E-23. The Charpy V- notch (Cv) energy in both the parallel and normal orientation with respect to the rolling direction of the flywheel material shall be at least 50 foot pounds at 70°F to demonstrate compliance with Regulatory Guide 1.14. A lower bound K_{Id} reference curve (see Figure 5.4-3) has been constructed from dynamic fracture toughness data generated in SA-533, Grade B, Class 1 steel [2]. All data points are plotted on the temperature scale relative to the NDTT. The construction of the lower bound curve below which no single test point falls, combined with the use of dynamic data when flywheel loading is essentially static, together represent a large degree of conservatism. Reference of this curve to the guaranteed NDTT of +10°F indicates that, at the predicted flywheel operating temperature of 110°F, the minimum fracture toughness is in excess of 10 KSI-in$^{1/2}$. This conforms to the Regulatory Guide 1.14 requirement that the dynamic stress intensity factor must be at least 100 KSI-in$^{1/2}$.

The fracture toughness properties of the Unit 1 and Unit 2 reactor coolant pump flywheels are shown in Table 5.4-19 and Table 5.4-19A, respectively.

Thus, it is concluded that flywheel plate materials are suitable for use and can meet Regulatory Guide 1.14 acceptance criteria on the bases of suppliers certification data.

5.4.2 STEAM GENERATOR

5.4.2A Unit 1 Steam Generators

5.4.2A.1 Steam Generator Materials

5.4.2A.1.1 Selection and Fabrication of Materials

All pressure boundary materials used in the steam generator are selected and fabricated in accordance with the requirements of Section III of the ASME Code. A general discussion of materials specifications is given in Section 5.2.3, with types of materials listed in Tables 5.2-2 and 5.2-3. Fabrication of reactor coolant pressure boundary materials is also discussed in Section 5.2.3, particularly in Sections 5.2.3.3 and 5.2.3.4.

Testing has justified the selection of corrosion-resistant thermally treated Inconel Alloy 690, a nickel-chromium-iron alloy (ASME-SB-163), for the steam generator tubes and divider plate. The interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. The primary side of the tubesheet is weld clad with Inconel (ASME-SB-163). The tubes are hydraulically expanded into the tubesheet holes after the ends are tack rolled and seal welded. The flush autogenous welds made to the tubesheet cladding are performed in compliance with Sections III and IX of the ASME Code and are thoroughly inspected before each tube is expanded.

Code cases used in material selection are discussed in Section 5.2.1. The extent of conformance with Regulatory Guides 1.84 and 1.85 is also discussed in Section 5.2.1 and Appendix 1A(N).

During manufacture, cleaning is performed on the primary and secondary sides of the steam generator in accordance with written procedures which follow the guidance of Regulatory Guide 1.37, “Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants,” and the ANSI Standard N45.2.1-1980, “Cleaning of Fluid Systems and Associated Components for Nuclear Power Plants.” Onsite cleaning and cleanliness control is in accordance with Westinghouse recommendations given in Westinghouse process specifications, as discussed in Section 5.2.3.4.

The fracture toughness of the materials is discussed in Section 5.2.3.3 and 5.3.1.5. Adequate fracture toughness of ferritic materials in the reactor coolant pressure boundary is provided by compliance with Appendix G of 10CFR50 and with NB-2300 of Section III of the ASME Code. Per the discussion in Section 5.4.2.3, consideration of fracture toughness is only necessary for materials used for Class 1 components.

5.4.2A.1.2 Steam Generator Design Effects on Materials

Several features are employed to control the regions where deposits would tend to accumulate. To avoid extensive crevice areas between the tube and tubesheet, the tubes are hydraulically expanded for the full depth surface of the tubesheet, after their ends are seal welded to the Inconel (ASME-SB-163) cladding on the primary side of the tubesheet. In addition, all tube support plates have trefoil-shaped holes configured to maximize flow adjacent to the tube so as to reduce the potential for chemical concentration in the regions where the tubes pass through the tube support plate.

5.4.2A.1.3 Compatibility of Steam Generator Tubing with Primary and Secondary Coolants

As mentioned in Section 5.4.2A.1.1, corrosion tests, which subjected the steam generator tubing material Inconel-600 (ASME-SB-163) to simulated steam generator water chemistry, have indicated that the loss due to general corrosion over the 40 year plant life is insignificant compared to the tube wall thickness. Testing to investigate the susceptibility of heat exchanger construction materials to stress corrosion in caustic and chloride aqueous solutions has indicated that Inconel-600 has excellent resistance to general corrosion in severe operating water conditions. Many reactor years of successful operation have shown the same low general corrosion rates as indicated by the laboratory tests. Recent operating experience, however, has revealed areas on secondary surfaces where localized corrosion rates were significantly greater than the low general corrosion rates. Both intergranular corrosion and tube wall thinning were experienced in localized areas, although not at the same location or under the same

environmental conditions (water chemistry, sludge composition). These localized areas of corrosion posed no threat to the public health and safety but were of concern because of their possible effect on plant availability.

To eliminate these localized areas of corrosion over the long term operation of the unit, it was decided that the use of phosphates for steam generator control would be eliminated. The adoption of the all volatile treatment (AVT) control program will minimize the possibility for recurrence of the tube wall thinning phenomenon related to poor phosphate chemistry control. Successful AVT operation requires maintenance of low concentrations of impurities in the steam generator water, thus reducing the potential for formation of highly concentrated solutions in low flow zones, one of the precursors for a corrosion mechanism. By restriction of the total alkalinity in the steam generator and prohibition of extended operation with free alkalinity, the AVT program will prevent the recurrence of intergranular corrosion in localized areas due to excessive levels of free caustic.

Laboratory testing has shown that the Inconel-600 tubing is compatible with the AVT environment. Isothermal corrosion testing in AVT water has shown that Inconel-600 at engineering stresses does not suffer intergranular stress corrosion cracking in extended exposures. Model boiler tests being conducted by Westinghouse have shown quite favorable results for AVT to date.

AVT chemistry control has been employed in plant operations successfully for considerable periods. Plants with stainless steel tubes which have demonstrated successful AVT operation include Selni, Sena and Yankee-Rowe. Selni has operated with AVT since 1964, Sena since 1966, and Yankee-Rowe since 1967.

AVT is the water treatment of preference for plants having Inconel-600 steam generator tubing. Among the plants which have operated successfully with AVT is Maine-Yankee (since 1972). The defects encountered in Inconel-600 tubed steam generators treated with AVT water treatment are primarily the result of the use of copper alloy materials in the secondary coolant side and continued operation with in-leakage of condenser cooling water. The defects are not expected to occur or will be minimized at CPNPP since the major components in the CPNPP secondary coolant side, including the condenser and moisture separator reheaters, are composed of non-copper base alloys. In addition, the appropriate corrective actions will be performed should condenser cooling water in-leakage occur.

Operating experience, verified in numerous steam generator inspections, indicates that the tube degradation associated with phosphate water treatment is not occurring where only AVT has been utilized. Adherence to the AVT chemical specifications and close monitoring of the condenser integrity will assure the continued good performance of the steam generator tubing.

Additional extensive operating data has been accumulated since the conversion to AVT chemistry. A comprehensive program of steam generator inspections, including the requirements of Regulatory Guide 1.83, with the exceptions as stated in Appendix 1A(N) has ensured detection and correction of any unanticipated degradation that occurred in the steam generator.

Even though the tube degradation associated with phosphate water treatment did not occur, numerous other modes of degradation mechanisms have occurred in A600MA tubing after several EFPY of operation. The major modes of degradation experienced are primary water

stress corrosion cracking (PWSCC), which occurs on the inside diameter of the steam generator tubing or the primary side, and outside diameter stress corrosion cracking (ODSCC) which occurs on the secondary side of the steam generator tubing. For the purposes of this discussion, ODSCC will also include contribution of intergranular attack (IGA).

The degradation of A600MA steam generators has resulted in high operational costs to the industry as a result of increased inspection and maintenance requirements and also through significant losses in availability. Consequently, the large majority of the A600MA Steam Generators has been replaced.[Reference 8] This includes Comanche Peak Unit 1. The replacement material for Comanche Peak Unit 1 is A690TT. This alloy has been shown through extensive laboratory testing and limited operational experience to be superior to A600MA tubing in both primary and secondary water chemistry environments. The results have been extensively evaluated and documented by EPRI in References 9-11, and will be summarized in the following discussion, including assessment of A600TT, which is the tubing material in Comanche Peak Unit 2.

The Unit 2 Model D5 was specifically considered in Reference 2. Improvement factors for the performance of A600TT tubing in the Model D5 Steam Generator versus A600MA tubing were calculated for specific degradation mechanisms as follows:

- The improvement factor for PWSCC = 5
- The improvement factor for ODSC = 4.5
- The improvement factor for the tube support ODSCC = 2.2

The overall predicted degradation for Model D5 (A600TT Tubing) Steam Generators calculations were based on an assumed hot leg temperature of 618 Degree F. Aggregate failures for all degradation modes at an estimated end of life of 51.0 EFPY are predicted to be 6.5% of the tubes. This represents a large improvement compared to A600MA performance.

Reference 9 calculated the predicted degradation for A690TT Tubing Steam Generators also based on an assumed hot leg temperature of 618 Deg. F. The results of this predictions was complemented by the improvement factor for PWSCC that was developed in another EPRI study, MRP-111, Reference 10. MRP-111 did not develop an improvement factor for ODSCC, therefore no comparison can be made.

The specific results of the predictions from Reference 9 and Reference 10 will not covered in detail as Reference 11 provided an extensive update to the improvement factors for A690TT. However, it should be noted from Reference 9 that the results from AVB wear was not specifically modeled due to the improved design and degradation history to date. Therefore the new designs were assumed to be essentially immune to AVB wear. AVB wear can be considered to be evaluated in the miscellaneous category. For the aggregate of the degradation mechanisms, no tubes are predicted to be plugged at the end of life of 51.0 EFPY. The miscellaneous category was predicted to be the leading cause of degradation and is predicted to be 5 tubes per 10,000 Steam Generator tubes at end of life.

Reference 11 provided an updated improvement factor for A690TT utilizing the following factors:

- Material improvement factors derived from additional laboratory testing data

- Overall improvement factors derived from plant experience was introduced into the evaluation, even though the actual experience time is still too limited to determine a improvement factor that is not very conservative

- Environmental weighing factors were considered by the derivation of an average material improvement factor for the environments tested in the laboratory studies

- Internals design improvement factors were considered such as the following:

    - Tube sheet expansion mechanism

    - Tube sheet crevice depth

    - Tube support material and geometry

- Overall improvement factors were calculated for replacement versus original steam generators using the Ginna Steam Generator (SG) replacement case

The updated improvement factors for A690TT versus A600MA for each specific degradation mechanism were calculated as follows:

- Expansion zone circumferential PWSCC = >40

- Expansion zone axial PWSCC = >200

- Denting PWSCC = >800

- Tube sheet ODSCC = >230

- Tube support ODSCC = >60

Utilizing these improvement factors, the time for the first observation of these failures were calculated for the Ginna replacement SG's with A690TT tubing based on the first observation of these failures in the original SG's with A600MA tubing. The results are as follows:

- PWSCC may be experienced in the Ginna replacement SG's after 200 EFPY.

- ODSCC may be experienced in the Ginna replacement SG's after 1450 EFPY.

While these estimates extend well beyond a reasonable extrapolation time for a typical plant life, they provide a great deal of confidence in the fact that replacement design Steam Generators with A690TT will operate well beyond their expected lifetime without experiencing significant degradation.

5.4.2A.1.4 Monitoring of Secondary Side Water Chemistry

The chemistry of the steam generator water and condensate is continuously monitored as described in Section 9.3.2 and 10.4.16 respectively. The conductivity and pH of the secondary side are continuously measured as are dissolved oxygen, sodium and hydrazine content. Addition rates of secondary side chemicals are controlled by the continuous on-line analyzers.

Steam generator blowdown is continuous; the rate can be adjusted using the water chemistry as a basis. The steam generator blowdown processing system is described in Section 10.4.8.

The approach to monitoring secondary side water chemistry complies with the approach outlined in Branch Technical Position MTEB 5-3.

5.4.2A.1.5 Cleanup of Secondary Side Materials

Several methods are employed to clean operating steam generators of corrosion causing secondary side deposits. Sludge lancing, a procedure in which a hydraulic jet inserted through an access opening (inspection port) loosens deposits which are removed by means of a suction pump, can be performed when the need is indicated by the results of steam generator tube inspection. Blowdown procedures are performed as deemed necessary by regular water chemistry testing. For the Delta 76 steam generators, the top of the tubesheet suction holes located along the tubelane facilitates the efficient removal of impurities that have accumulated on the tubesheet.

5.4.2A.2 Steam Generator Inservice Inspection

5.4.2A.2.1 Steam Generator Design Characteristics For Inservice Inspection

The steam generator is designed to permit inservice inspection of Class 1 and 2 components, including individual tubes. The design aspects that provide access for inspection and the proposed inspection program comply with the edition of Section XI of the ASME Code, Division 1, “Rules for Inspection and Testing of Components of Light- Water-Cooled Plants,” required by 10 CFR 50.55a, paragraph g. A number of access openings make it possible to inspect and repair or replace a component according to the techniques specified. These openings include four manways, two of them for inspection and maintenance of the steam dryer. Also the Unit 1 steam generators have four 6.0 inch diameter handholes, four 4.0 inch diameter inspection openings and sixteen 2.5 inch diameter inspection openings.

5.4.2A.2.2 Program For Inservice Inspection Of Steam Generator Tubing

Steam generator tubing will be inspected in accordance with:

1. The recommendations given in Regulatory Guide 1.83, “Inservice Inspection of Steam Generator Tubes,” Revision 1, July 1975, and

2. The requirements of ASME Section XI (Edition and Addenda as required by 10CFR50.55a), Subarticle IWB-2413.

3. Comanche Peak Nuclear Power Plant Technical Specifications Section 5.5.9.

The program consists of the following areas:

<u>Inspection Equipment & Procedures</u>

Eddy current testing equipment will be used to inspect the tubing and shall be sensitive enough to detect imperfections of 20 percent or more through the tube wall.

Baseline Inspection

1. All tubes in the steam generators shall be inspected by eddy current or alternative techniques prior to service to establish a baseline condition of the tubing.

2. If a major change in their secondary water chemistry is made during plant lifetime, a baseline inspection will be conducted before resumption of power operation.

Steam Generator Sample Selection and Inspection

Steam Generator Sample Selection and Inspection shall be consistent with CPNPP TS 5.5.9.

Steam Generator Tube Inspection Techniques and Tubes Left in Service Based on Indication Size (GL 97-05).

Traditionally, eddy-current inspection techniques are relied upon to assess the condition of steam generator tubes. Although the eddy-current method is a proven technique for detecting tube degradation, the ability to depth size indications is possible only for specific modes of degradation. Specifically, tube degradation from inter-granular attack (IGA) and stress corrosion cracking (SCC), major modes of steam generator tube degradation, are difficult to size with eddy-current inspection techniques because of a number of complicating variables. Theoretically, there is a relationship between the depth of penetration of a defect and the eddy-current signal response; in practice, however, the relationship between signal voltage or phase angle and the degradation depth is influenced by many other variables. Oxide deposits, variability of tube material properties and geometry, degradation morphology, human factors, and eddy-current data analysis and acquisition practices are some of the factors that can significantly alter a depth estimation of steam generator tube degradation. The depth of several specific forms of volumetric steam generator tube degradation can be sized with a reasonable degree of accuracy; however, qualifying techniques for sizing of some forms of degradation, e.g., IGA and SCC, are typically problematic.

CPNPP has adopted the guidelines of Energy Institute (NEI) letter 97-06, “Steam Generator Program Guidelines”. NEI 97-06 requires following the inspection guidelines contained in the latest revision of the Electric Power Research Institute (EPRI) Pressurized Water Reactor (PWR) Steam Generator Examination Guidelines.

Appendix H, “Performance Demonstration for Eddy Current Examination,” of the EPRI “PWR Steam Generator Examination Guidelines,” latest revision, provides guidance on the qualification of steam generator tubing examination techniques and equipment used to detect and size indications. Damage mechanisms are divided into the following categories: thinning, pitting, wear, outside diameter inter-granular attack/stress-corrosion cracking (IGA/SCC), primary-side SCC, and impingement damage for qualification.

For qualification purposes, test samples are used to evaluate detection and sizing capabilities. While pulled tube samples are preferred, fabricated samples may be used. If fabricated test samples are used, the samples are verified to produce signals similar to those being observed in the field in terms of signal characteristics, signal amplitude, and signal-to-noise ratio. Samples are examined to determine the actual through wall defect measurements as part of the Appendix H qualification process.

The procedures at CPNPP are developed in accordance with Appendix H which specifies the essential variables for each technique. These essential variables are associated with an individual instrument, probe, cable, or particular equipment configurations. Additionally, certain techniques have undergone testing and review to quantify sizing performance. The sizing data set includes the detection data set for the technique with additional requirements for number and composition of the grading units.

At CPNPP only tubes with indications of wear type degradation found at anti-vibration bars and tube support plates and which are less than the Technical Specification value of 40% are permitted to remain in service. All tubes with crack-like degradation are plugged upon detection.

5.4.2A.3 Design Bases

Steam generator design data are given in Table 5.4-3. Code classifications of the steam generator components are given in Section 3.2. Although the ASME classification for the secondary side is specified to be Class 2, the current philosophy is to design all pressure retaining parts of the steam generator, and thus, both the primary and secondary pressure boundaries, to satisfy the criteria specified in Section III of the ASME Code for Class 1 components. The design stress limits, transient conditions and combined loading conditions applicable to the steam generator, are discussed in Section 3.9N.1. Estimates of radioactivity levels anticipated in the secondary side of the steam generators during normal operation, and the bases for the estimates, are given in Chapter 11. The accident analysis of a steam generator tube rupture is discussed in Chapter 15.

The internal moisture separation equipment is designed to ensure that moisture carryover does not exceed 0.10 percent of weight under the following conditions:

1. Steady state operation up to 100 percent of full load steam flow, with water at the normal operating level.

2. Loading or unloading at a rate of 5 percent of full power steam flow per minute in the range from 15 to 100 percent of full load steam flow.

3. A step load change of 10 percent of full power in the range from 15 to 100 percent full load steam flow.

The water chemistry on the reactor side is selected to provide the necessary boron content for reactivity control and to minimize corrosion of RCS surfaces. The water chemistry of the steam side and its effectiveness in corrosion control are discussed in Chapter 10. Compatibility of steam generator tubing with both primary and secondary coolants is discussed further in Section 5.4.2A.1.3.

The steam generator is designed to prevent unacceptable damage from mechanical or flow induced vibration. Tube support adequacy is discussed in Section 5.4.2A.5.3. The tubes and tubesheet are analyzed and confirmed to withstand the maximum accident loading condition as it is defined in Section 3.9(N).1. Further consideration is given in Section 5.4.2A.5.4 to the effect of tube wall thinning on accident condition stresses.

5.4.2A.4 Design Description

The steam generator shown in Figure 5.4-4A is a Delta 76, vertical shell and U-tube evaporator with integral moisture separating equipment. On the primary side, the reactor coolant flows through the inverted U-tubes, entering and leaving through nozzles located in the hemispherical bottom head of the steam generator. The head is divided into inlet and outlet chambers by a vertical divider plate extending from the head to the tubesheet. Steam is generated on the shell side, flows upward and exits through the outlet nozzle at the top of the vessel. During normal operation, subcooled feedwater is supplied from the plant feedwater system and enters the steam generator through the main (or sometimes auxiliary) feedwater inlet nozzle located in the upper shell of the steam generator. Inside the steam generator, the feedwater is joined by the recirculating water separated from the steam-water mixture by the moisture separators, producing a subcooled mixture in the upper plenum that is slightly below saturation temperature. The subcooled mixture flow down the downcomer annulus formed by the I.D. of the steam generator shell and the O.D. of the wrapper, then enters the lower tube bundle through an opening between the lower edge of the wrapper and the secondary surface of the tubeplate. Subsequently the water-steam mixture flows upward through the tube bundle and into the steam drum section, where individual centrifugal moisture separators remove most of the entrained water from the steam. The steam continues to the secondary separators for further moisture removal, increasing its quality to a minimum of 99.9 percent. The moisture separators recirculate the separated water through the annulus between the shell and tube bundle wrapper. The returning flow then combines with the feedwater for another passage through the steam generator. Dry steam exits through the outlet nozzle which is provided with a steam flow restrictor, described in Section 5.4.4.

5.4.2A.5 Design Evaluation

5.4.2A.5.1 Forced Convection

The limiting case for heat transfer capability is the “nominal 100 percent design” case. The steam generator effective heat transfer coefficient is based on the coolant conditions of temperature and flow for this case. The best estimate for the heat transfer coefficient applied in steam generator design calculations and plant parameter selection is approximately 1250 Btu/hr-ft2-oF. The coefficient incorporates a specified fouling factor resistance of 0.00011 hr/ft2-oF/Btu which is the value selected to account for the differences in the measured and calculated heat transfer performance as well as provide design margin. Although margin for tube fouling is available, operating experience to date has not indicated that steam generator performance decreases over a long time period. Adequate tube area is selected to ensure that the full design heat removal rate is achieved.

5.4.2A.5.2 Natural Circulation Flow

The driving head created by the change in coolant density as it is heated in the core and rises to the outlet nozzle initiates convection circulation. This circulation is enhanced by the fact that the steam generators, which provide a heat sink, are at a higher elevation than the reactor core which is the heat source. Thus natural circulation is assured for the removal of decay heat during hot shutdown in the unlikely event of loss of forced circulation.

5.4.2A.5.3 Mechanical and Flow Induced Vibration Under Normal Operation

In the design of Westinghouse steam generators, the potential for tube wall degradation attributable to mechanical or flow induced excitation has been thoroughly evaluated. The evaluation included detailed analyses of the tube support systems for various mechanisms of tube vibration.

The primary cause of tube vibration in heat exchangers is hydrodynamic excitation due to secondary fluid flow on the outside of the tubes. In the range of normal steam generator operating conditions, the affects of primary fluid flow inside the tubes and mechanically induced tube vibration are considered to be negligible.

To evaluate flow induced tube vibration in the tube bundle, detailed analyses have been performed employing data from operating plants, full and partial scale model tests and analytical tube vibration models. Parallel flow analyses indicate that the flow velocities are sufficiently low such that they result in negligible fatigue and vibratory amplitudes. The support system, therefore, is deemed adequate with regard to parallel flow excitation.

To evaluate cross flow at the exit of the downcomer flow to the tube bundle and at the top of the bundle in the U-bend area, Westinghouse performed an experimental research program of cross flow in tube arrays with the specific parameters of the steam generator. Air and water model tests were employed. The results of this research indicate that these regions of the bundle are not subject to the vortex shedding mechanism of tube excitation. Vortex shedding was found not to be a significant mechanism in these two regions for the following reasons:

1. Flow turbulence in the downcomer and tube bundle inlet region inhibit the formation of Von Karman vorticies.

2. Both axial and cross flow velocity components exist on the tubes. The axial flow component disrupts the Von Karman vortices.

This research program was also the basis for evaluation of the fluidelastic mechanism due to cross flow at the tubesheet and at the top of the bundle in the U-bend area. The evaluation showed the adequacy of the tube support arrangement.

Flow turbulence can result in some tube excitation in these regions. This excitation is of little concern, however, since:

1. Maximum stresses in the tubes are below the fatigue endurance limit of the tube material, and

2. Tube support arrangements preclude significant vibratory motion.

In summary, tube vibration has been thoroughly evaluated. Mechanical and primary flow excitation are considered negligible. Secondary flow excitation has been evaluated. From this evaluation, it is concluded that if tube vibration does occur, the magnitude will be limited. Tube fatigue due to the vibration is judged to be negligible. Any tube wear resulting from the tube vibration would be limited and would progress slowly. This allows use of a periodic tube inservice inspection program for detection and follow of any tube wear. This inservice inspection program, in conjunction with tube plugging criteria, provides for safe operation of the steam generators.

5.4.2A.5.4 Allowable Tube Wall Thinning Under Accident Conditions

For tube plugging, the criteria is found in Section 1(A)N.

5.4.2A.6 Quality Assurance

The steam generator quality assurance program is given in Table 5.4-4A.

Radiographic inspection and acceptance standard shall be in accordance with the requirements of Section III of the ASME Code.

Liquid penetrant inspection is performed on weld deposited tubesheet cladding, channel head cladding, and tube-to-tubesheet weldments. Liquid penetrant inspection and acceptance standards are in accordance with the requirements of Section III of the ASME Code.

Magnetic particle inspection is performed on the tubesheet forging, channel head forging, nozzle forgings, and the following weldments:

1. Nozzles to shell.

2. Instrument connection (primary and secondary).

3. Temporary attachments after removal.

4. All accessible pressure containing welds after hydrostatic test.

Magnetic particle inspection and acceptance standard are in accordance with requirements of Section III of the ASME Code.

An ultrasonic test is performed on the tubesheet forging, tubesheet cladding, channel head forging, secondary shell and head forging and nozzle forgings.

The heat transfer tubing is subjected to eddy current and ultrasonic tests.

Hydrostatic tests are performed in accordance with Section III of the ASME Code.

In addition, the heat transfer tubes shall be subjected to a hydrostatic test pressure prior to installation into the vessel which is not less than 1.25 times the primary side design pressure.

5.4.2B Unit 2 Steam Generators

5.4.2B.1 Steam Generator Materials

5.4.2B.1.1 Selection and Fabrication of Materials

All pressure boundary materials used in the steam generator are selected and fabricated in accordance with the requirements of Section III of the ASME Code. A general discussion of materials specifications is given in Section 5.2.3, with types of materials listed in Tables 5.2-2 and 5.2-3. Fabrication of reactor coolant pressure boundary materials is also discussed in Section 5.2.3, particularly in Sections 5.2.3.3 and 5.2.3.4.

Testing has justified the selection of corrosion-resistant Inconel- 600, a nickel-chromium-iron alloy (ASME-SB-163), for the steam generator tubes and divider plate. The interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. The primary side of the tubesheet is weld clad with Inconel (ASME-SB-163). The tubes are mechanically or explosively expanded into the tubesheet holes after the ends are tack rolled and seal welded. The recessed fusion welds made to the tubesheet cladding are performed in compliance with Sections III and IX of the ASME Code and are thoroughly inspected before each tube is expanded.

Approximately 100 tubes in the preheat section of unit 1 and 2 steam generators have been hydraulically expanded at the “B” and “D” support plate elevations to reduce the tube vibration phenomena experienced in Westinghouse counterflow preheat steam generators. The material properties of the expanded section of the tubes are discussed in Reference 4.

Code cases used in material selection are discussed in Section 5.2.1. The extent of conformance with Regulatory Guides 1.84 and 1.85 is also discussed in Section 5.2.1 and Appendix 1A(N).

During manufacture, cleaning is performed on the primary and secondary sides of the steam generator in accordance with written procedures which follow the guidance of Regulatory Guide 1.37, “Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants,” and the ANSI Standard N45.2.1- 1973, “Cleaning of Fluid Systems and Associated Components for Nuclear Power Plants.” Onsite cleaning and cleanliness control is in accordance with Westinghouse recommendations given in Westinghouse process specifications, as discussed in Section 5.2.3.4.

The fracture toughness of the materials is discussed in Section 5.2.3.3 and 5.3.1.5. Adequate fracture toughness of ferritic materials in the reactor coolant pressure boundary is provided by compliance with Appendix G of 10CFR50 and with NB-2300 of Section III of the ASME Code. Per the discussion in Section 5.4.2.3, consideration of fracture toughness is only necessary for materials used for Class 1 components.

5.4.2B.1.2 Steam Generator Design Effects on Materials

Several features are employed to control the regions where deposits would tend to accumulate. To avoid extensive crevice areas between the tube and tubesheet, the tubes are roller, explosively or hydraulically expanded for the full depth surface of the tubesheet, after their ends are seal welded to the Inconel (ASME-SB-163) cladding on the primary side of the tubesheet. A flow distribution plate located below the preheat section encourages recirculating flow to sweep the tubesheet before turning upward through the tube bundle. This plate also serves to separate the tubesheet from the colder feedwater entering at the preheat section. A separate auxiliary feedwater nozzle provided in the upper shell avoids introducing cold water into the preheat section, and, thus, maximizes the integrity of steam generator materials.

5.4.2B.1.3 Compatibility of Steam Generator Tubing with Primary and Secondary Coolants

As mentioned in Section 5.4.2.B1.1, corrosion tests, which subjected the steam generator tubing material Inconel-600 (ASME-SB-163) to simulated steam generator water chemistry, have indicated that the loss due to general corrosion over the 40 year plant life is insignificant compared to the tube wall thickness. Testing to investigate the susceptibility of heat exchanger

construction materials to stress corrosion in caustic and chloride aqueous solutions has indicated that Inconel-600 has excellent resistance to general corrosion in severe operating water conditions. Many reactor years of successful operation have shown the same low general corrosion rates as indicated by the laboratory tests. Recent operating experience, however, has revealed areas on secondary surfaces where localized corrosion rates were significantly greater than the low general corrosion rates. Both intergranular corrosion and tube wall thinning were experienced in localized areas, although not at the same location or under the same environmental conditions (water chemistry, sludge composition). These localized areas of corrosion posed no threat to the public health and safety but were of concern because of their possible effect on plant availability.

To eliminate these localized areas of corrosion over the long term operation of the unit, it was decided that the use of phosphates for steam generator control would be eliminated. The adoption of the all volatile treatment (AVT) control program will minimize the possibility for recurrence of the tube wall thinning phenomenon related to poor phosphate chemistry control. Successful AVT operation requires maintenance of low concentrations of impurities in the steam generator water, thus reducing the potential for formation of highly concentrated solutions in low flow zones, one of the precursors for a corrosion mechanism. By restriction of the total alkalinity in the steam generator and prohibition of extended operation with free alkalinity, the AVT program will prevent the recurrence of intergranular corrosion in localized areas due to excessive levels of free caustic.

Laboratory testing has shown that the Inconel-600 tubing is compatible with the AVT environment. Isothermal corrosion testing in AVT water has shown that Inconel-600 at engineering stresses does not suffer intergranular stress corrosion cracking in extended exposures. Model boiler tests being conducted by Westinghouse have shown quite favorable results for AVT to date.

AVT chemistry control has been employed in plant operations successfully for considerable periods. Plants with stainless steel tubes which have demonstrated successful AVT operation include Selni, Sena and Yankee-Rowe. Selni has operated with AVT since 1964, Sena since 1966, and Yankee-Rowe since 1967.

AVT is the water treatment of preference for plants having Inconel-600 steam generator tubing. Among the plants which have operated successfully with AVT is Maine-Yankee (since 1972). The defects encountered in Inconel-600 tubed steam generators treated with AVT water treatment are primarily the result of the use of copper alloy materials in the secondary coolant side and continued operation with in-leakage of condenser cooling water. The defects are not expected to occur or will be minimized at CPNPP since the major components in the CPNPP secondary coolant side, including the condenser and moisture separator reheaters, are composed of non-copper base alloys. In addition, the appropriate corrective actions will be performed should condenser cooling water in-leakage occur.

A number of design changes have been incorporated in the Model D5 steam generators for CPNPP Unit 2. These changes have been incorporated to reduce the consequences of adverse secondary side environmental conditions and hence improve overall steam generator reliability.

The tube support plates used in the Model D5 will be ferritic stainless steel which has been shown in laboratory tests to be resistant to corrosion in the AVT environment. When corrosion of ferritic stainless steel does occur, the volume of the corrosion products is equivalent to the

volume of the consumed material. The support plates have also been designed with broached tube holes (quatrefoil design) rather than drilled holes. The broached tube hole design promotes high velocity flow along the tube sweeping any impurities away from the support plate location.

Additional measures are incorporated in the Model D5 design to prevent areas of dryout in the steam generator and accumulations of sludge in low velocity areas. Modification to the wrapper have increased water velocities across the tubesheet. A flow distribution baffle is provided which forces the low flow area to the center of the bundle. Increased capacity blowdown pipes have been added to enable continuous blowdown of the steam generators at a high volume. The intakes of these blowdown pipes are located below the center cut-out section of the flow distribution baffle in the low velocity region where sludge may be expected to accumulate. Continuous blowdown provides maximum protection against inleakage of impurities from the condenser.

Thermal treatment of Inconel tubes has been shown to be effective in limiting stress corrosion cracking, especially in the U-bend region and the expanded region at the tubesheet. Tubing used in the Model D5 steam generators (Unit 2) have been thermally treated at the factory to provide additional margin against inner diameter primary water stress corrosion cracking.

Operating experience, verified in numerous steam generator inspections, indicates that the tube degradation associated with phosphate water treatment is not occurring where only AVT has been utilized. Adherence to the AVT chemical specifications and close monitoring of the condenser integrity will assure the continued good performance of the steam generator tubing.

Additional extensive operating data is presently being accumulated with the conversion to AVT chemistry. A comprehensive program of steam generator inspections, including the requirements of Regulatory Guide 1.83, with the exceptions as stated in Appendix 1A(N) will ensure detection and correction of any unanticipated degradation that might occur in the steam generator.

5.4.2B.1.4 Monitoring of Secondary Side Water Chemistry

The chemistry of the steam generator water and condensate is continuously monitored as described in Section 9.3.2 and 10.4.16 respectively. The conductivity and pH of the secondary side are continuously measured as are dissolved oxygen, sodium and hydrazine content. Addition rates of secondary side chemicals are controlled by the continuous on-line analyzers. Steam generator blowdown is continuous; the rate can be adjusted using the water chemistry as a basis. The steam generator blowdown processing system is described in Section 10.4.8.

The approach to monitoring secondary side water chemistry complies with the approach outlined in Branch Technical Position MTEB 5-3.

5.4.2B.1.5 Cleanup of Secondary Side Materials

Several methods are employed to clean operating steam generators of corrosion causing secondary side deposits. Sludge lancing, a procedure in which a hydraulic jet inserted through an access opening (inspection port) loosens deposits which are removed by means of a suction pump, can be performed when the need is indicated by the results of steam generator tube inspection. Blowdown procedures are performed as deemed necessary by regular water chemistry testing. The location of the blowdown piping suction, adjacent to the tubesheet and in

a region of relatively low flow velocity, facilitates the efficient removal of impurities that have accumulated on the tubesheet.

5.4.2B.2 Steam Generator Inservice Inspection

5.4.2B.2.1 Steam Generator Design Characteristics For Inservice Inspection

The steam generator is designed to permit inservice inspection of Class 1 and 2 components, including individual tubes. The design aspects that provide access for inspection and the proposed inspection program comply with the edition of Section XI of the ASME Code, Division 1, "Rules for Inspection and Testing of Components of Light- Water-Cooled Plants," required by 10 CFR 50.55a, paragraph g. A number of access openings make it possible to inspect and repair or replace a component according to the techniques specified. These openings include four manways, two of them for inspection and maintenance of the steam dryer. Also the Unit 2 steam generators have five 6.0 inch diameter handholes and three 2.5 inch diameter inspection openings for additional access through the secondary side pressure boundary.

5.4.2B.2.2 Program For Inservice Inspection Of Steam Generator Tubing

Steam generator tubing will be inspected in accordance with:

1. The recommendations given in Regulatory Guide 1.83, "Inservice Inspection of Steam Generator Tubes," Revision 1, July 1975, and

2. The requirements of ASME Section XI (Edition and Addenda as required by 10CFR50.55a), Subarticle IWB-2413.

3. Comanche Peak Nuclear Power Plant Technical Specifications Section 5.5.9.

The program consists of the following areas:

Inspection Equipment & Procedures

Eddy current testing equipment will be used to inspect the tubing and shall be sensitive enough to detect imperfections of 20 percent or more through the tube wall.

Baseline Inspection

1. All tubes in the steam generators shall be inspected by eddy current or alternative techniques prior to service to establish a baseline condition of the tubing.

2. If a major change in their secondary water chemistry (e.g., phosphate to volatile treatment) is made during plant lifetime, a baseline inspection will be conducted before resumption of power operation.

Steam Generator Sample Selection and Inspection

Steam Generator Sample Selection and Inspection shall be consistent with CPNPP TS 5.5.9.

Steam Generator Tube Inspection Techniques and Tubes Left in Service Based on Indication Size (GL 97-05)

Traditionally, eddy-current inspection techniques are relied upon to assess the condition of steam generator tubes. Although the eddy-current method is a proven technique for detecting tube degradation, the ability to depth size indications is possible only for specific modes of degradation. Specifically, tube degradation from inter-granular attack (IGA) and stress corrosion cracking (SCC), major modes of steam generator tube degradation, are difficult to size with eddy-current inspection techniques because of a number of complicating variables. Theoretically, there is a relationship between the depth of penetration of a defect and the eddy-current signal response; in practice, however, the relationship between signal voltage or phase angle and the degradation depth is influenced by many other variables. Oxide deposits, variability of tube material properties and geometry, degradation morphology, human factors, and eddy-current data analysis and acquisition practices are some of the factors that can significantly alter a depth estimation of steam generator tube degradation. The depth of several specific forms of volumetric steam generator tube degradation can be sized with a reasonable degree of accuracy; however, qualifying techniques for sizing of some forms of degradation, e.g., IGA and SCC, are typically problematic.

CPNPP has adopted the guidelines of Energy Institute (NEI) letter 97-06, “Steam Generator Program Guidelines”. NEI 97-06 requires following the inspection guidelines contained in the latest revision of the Electric Power Research Institute (EPRI) Pressurized Water Reactor (PWR) Steam Generator Examination Guidelines. Appendix H, “Performance Demonstration for Eddy Current Examination,” of the EPRI “PWR Steam Generator Examination Guidelines,” latest revision, provides guidance on the qualification of steam generator tubing examination techniques and equipment used to detect and size indications. Damage mechanisms are divided into the following categories: thinning, pitting, wear, outside diameter inter-granular attack/stress-corrosion cracking (IGA/SCC), primary-side SCC, and impingement damage for qualification.

For qualification purposes, test samples are used to evaluate detection and sizing capabilities. While pulled tube samples are preferred, fabricated samples may be used. If fabricated test samples are used, the samples are verified to produce signals similar to those being observed in the field in terms of signal characteristics, signal amplitude, and signal-to-noise ratio. Samples are examined to determine the actual through wall defect measurements as part of the Appendix H qualification process.

The procedures at CPNPP are developed in accordance with Appendix H which specifies the essential variables for each technique. These essential variables are associated with an individual instrument, probe, cable, or particular equipment configurations. Additionally, certain techniques have undergone testing and review to quantify sizing performance. The sizing data set includes the detection data set for the technique with additional requirements for number and composition of the grading units.

At CPNPP only tubes with indications of wear type degradation found at anti-vibration bars and tube support plates and which are less than the Technical Specification value of 40% are permitted to remain in service. All tubes with crack-like degradation are plugged upon detection.

5.4.2B.3 Design Bases

Steam generator design data are given in Table 5.4-3. Code classifications of the steam generator components are given in Section 3.2. Although the ASME classification for the secondary side is specified to be Class 2, the current philosophy is to design all pressure retaining parts of the steam generator, and thus, both the primary and secondary pressure boundaries, to satisfy the criteria specified in Section III of the ASME Code for Class 1 components. The design stress limits, transient conditions and combined loading conditions applicable to the steam generator, are discussed in Section 3.9N.1. Estimates of radioactivity levels anticipated in the secondary side of the steam generators during normal operation, and the bases for the estimates, are given in Chapter 11. The accident analysis of a steam generator tube rupture is discussed in Chapter 15.

The internal moisture separation equipment is designed to ensure that moisture carryover does not exceed 0.25 percent of weight under the following conditions:

1. Steady state operation up to 100 percent of full load steam flow, with water at the normal operating level.

2. Loading or unloading at a rate of 5 percent of full power steam flow per minute in the range from 15 to 100 percent of full load steam flow.

3. A step load change of 10 percent of full power in the range from 15 to 100 percent full load steam flow.

The water chemistry on the reactor side is selected to provide the necessary boron content for reactivity control and to minimize corrosion of RCS surfaces. The water chemistry of the steam side and its effectiveness in corrosion control are discussed in Chapter 10. Compatibility of steam generator tubing with both primary and secondary coolants is discussed further in Section 5.4.2B.1.3.

The steam generator is designed to prevent unacceptable damage from mechanical or flow induced vibration. Tube support adequacy is discussed in Section 5.4.2B.5.3. The tubes and tubesheet are analyzed in Reference [3] and confirmed to withstand the maximum accident loading condition as it is defined in Section 3.9N.1. Further consideration is given in Section 5.4.2B.5.4 to the effect of tube wall thinning on accident condition stresses.

The preheat section of the steam generator is arranged to provide the maximum amount of counter flow feasible and, therefore, more efficient heat transfer.

A separate auxiliary feedwater nozzle is provided in the upper shell in order to avoid introducing cold water into the possible hot and empty preheat section. The integrity of the steam generator design is, thus, maximized.

5.4.2B.4 Design Description

The steam generator shown in Figure 5.4-4B is a model D4, vertical shell and U-tube evaporator with integral moisture separating equipment. On the primary side, the reactor coolant flows through the inverted U-tubes, entering and leaving through nozzles located in the hemispherical bottom head of the steam generator. The head is divided into inlet and outlet chambers by a

vertical divider plate extending from the head to the tubesheet. Steam is generated on the shell side, flows upward and exits through the outlet nozzle at the top of the vessel. During normal operation, feedwater flows through a flow restrictor, directly into the counter flow preheat section and is heated almost to saturation temperature before entering the boiler section. Subsequently the water-steam mixture flows upward through the tube bundle and into the steam drum section, where individual centrifugal moisture separators remove most of the entrained water from the steam. The steam continues to the secondary separators for further moisture removal, increasing its quality to a minimum of 99.75 percent. The moisture separators recirculate the separated water through the annulus between the shell and tube bundle wrapper via the space formed by the distribution plate, between the tubesheet and the preheat section. The returning flow then combines with the already preheated water-steam mixture for another passage through the steam generator. Dry steam exits through the outlet nozzle which is provided with a steam flow restrictor, described in Section 5.4.4.

5.4.2B.5 Design Evaluation

5.4.2B.5.1 Forced Convection

The limiting case for heat transfer capability is the “nominal 100 percent design” case. The steam generator effective heat transfer coefficient is based on the coolant conditions of temperature and flow for this case. The best estimate for the heat transfer coefficient applied in steam generator design calculations and plant parameter selection is 1301 Btu/hr-ft^2-°F. This coefficient is approximately 5 to 10 percent less than the heat transfer performance experienced at a number of operating plants. The coefficient incorporates a specified fouling factor resistance of 0.00005 hr/ft^2-°F/Btu (0.0001 in the preheat section) which is the value selected to account for the differences in the measured and calculated heat transfer performance as well as provide the margin indicated above. Although margin for tube fouling is available, operating experience to date has not indicated that steam generator performance decreases over a long time period. Adequate tube area is selected to ensure that the full design heat removal rate is achieved.

5.4.2B.5.2 Natural Circulation Flow

The driving head created by the change in coolant density as it is heated in the core and rises to the outlet nozzle initiates convection circulation. This circulation is enhanced by the fact that the steam generators, which provide a heat sink, are at a higher elevation than the reactor core which is the heat source. Thus natural circulation is assured for the removal of decay heat during hot shutdown in the unlikely event of loss of forced circulation.

5.4.2B.5.3 Mechanical and Flow Induced Vibration Under Normal Operation

In the design of Westinghouse steam generators, the potential for tube wall degradation attributable to mechanical or flow induced excitation has been thoroughly evaluated. The evaluation included detailed analyses of the tube support systems for various mechanisms of tube vibration.

The primary cause of tube vibration in heat exchangers is hydrodynamic excitation due to secondary fluid flow on the outside of the tubes. In the range of normal steam generator operating conditions, the affects of primary fluid flow inside the tubes and mechanically induced tube vibration are considered to be negligible.

To evaluate flow induced tube vibration in the preheater region of the tube bundle, Westinghouse undertook an extensive program employing data from operating plants, full and partial scale model tests and analytical tube vibration models. Operating plant data consisted of tube wear data from pulled tube evaluations and eddy current tests, and tube motion data from accelerometers installed inside selected tubes. Model testing generated tube wear data, flow velocity distributions, tube motion parameters and flow induced tube vibration forcing functions. The tube vibration analyses applied the forcing functions to produce tube motion data. The results of this evaluation were consistent with the early operating experience of preheat steam generators.

On the basis of an extensive model test and analysis program, Westinghouse designed, verified and implemented a modification to the steam generator to reduce tube vibratory response to preheater inlet flow excitation. Additionally, the magnitude of the flow forcing function was reduced through implementation of a preheater flow bypass arrangement in the feedwater system. The verification of the performance of the modifications in reducing tube excitation and response was done with input from a full scale test under simulated conservative flow and tube support conditions.

Fatigue of the tubes in the preheater region which are subject to flow induced excitation is not a concern since the maximum resultant stresses in the tube are below the endurance limit of the material.

For areas of the tube bundle other than the preheater, parallel flow analyses were performed to determine the vibratory deflections. These analyses indicate that the flow velocities are sufficiently low such that they result in negligible fatigue and vibratory amplitudes. The support system, therefore, is deemed adequate with regard to parallel flow excitation.

To evaluate cross flow at the exit of the downcomer flow to the tube bundle and at the top of the bundle in the U-bend area, Westinghouse performed an experimental research program of cross flow in tube arrays with the specific parameters of the steam generator. Air and water model tests were employed. The results of this research indicate that these regions of the bundle are not subject to the vortex shedding mechanism of tube excitation. Vortex shedding was found not to be a significant mechanism in these two regions for the following reasons:

1. Flow turbulence in the downcomer and tube bundle inlet region inhibit the formation of Von Karman vortices.

2. Both axial and cross flow velocity components exist on the tubes. The axial flow component disrupts the Von Karman vortices.

This research program was also the basis for evaluation of the fluidelastic mechanism due to cross flow at the tubesheet. The evaluation showed the adequacy of the tube support arrangement.

Flow turbulence can result in some tube excitation in these regions. This excitation is of little concern, however, since:

1. Maximum stresses in the tubes are at least an order of magnitude below the fatigue endurance limit of the tube material, and

2. Tube support arrangements preclude significant vibratory motion.

In summary, tube vibration has been thoroughly evaluated. Mechanical and primary flow excitation are considered negligible. Secondary flow excitation has been evaluated. From this evaluation, it is concluded that if tube vibration does occur, the magnitude will be limited. Tube fatigue due to the vibration is judged to be negligible. Any tube wear resulting from the tube vibration would be limited and would progress slowly. This allows use of a periodic tube inservice inspection program for detection and follow of any tube wear. This inservice inspection program, in conjunction with tube plugging criteria, provides for safe operation of the steam generators.

5.4.2B.5.4 Allowable Tube Wall Thinning Under Accident Conditions

An evaluation is performed to determine the extent of tube wall thinning that can be tolerated under accident conditions. Under such a postulated design basis accident, vibration is of short enough duration that there is no endurance problem. The results of a study made on “D series” (0.75 inch nominal diameter, 0.043 inch nominal thickness) tubes under accident loading are discussed in Reference [3] and show that a minimum wall thickness of 0.026 inches would have a maximum faulted condition stress (i.e., due to combined LOCA and Safe Shutdown Earthquake loads) that is less than the allowable limit. This thickness is 0.010 inches less than the minimum steam generator tube wall thickness 0.039 reduced to 0.036 inches by the assumed general corrosion and erosion loss of 0.003 inches. However, 0.026 inches is not the limiting minimum wall thickness but rather is a more conservative value. For tube plugging, the criteria is found in Section 1(A)N.

The corrosion rate is based on a conservative weight loss rate for mill annealed Inconel tubing in flowing 650°F primary side reactor coolant fluid. The weight loss, when equated to a thinning rate and projected over a 40 year plant life with appropriate reduction after initial hours, is equivalent to 0.080 mils thinning. The assumed corrosion rate of 3 mils leaves a conservative 2.2 mils for general corrosion thinning on the secondary side. These values, as noted, have been developed for mill annealed material; a comparable set of data for thermally treated Inconel is being generated.

The steam generator tubes, existing originally at their minimum wall thickness and reduced by a very conservative general corrosion loss, still provide quite an adequate safety margin. Thus, it can be concluded that the ability of the steam generator tubes to withstand accident loadings is not affected by a lifetime of general corrosion losses.

5.4.2B.5.5 Steam Generator Denting

Localized steam generator tube diameter reductions were first discovered during the April 1975 steam generator inspection at the Surry Unit No. 2 plant. This discovery was evidenced by eddy current signals, resembling those produced by scanning dents, and by difficulty in passing the standard 0.700 in. diameter eddy current probe through the tubes at the intersections with the support plates. Subsequent to the initial finding, steam generator inspections at other operating plants revealed essentially identical results.

Denting is a term which describes a group of related phenomena resulting from corrosion of carbon steel in the crevices formed between the tubes and the tube support plates or tubesheets. The term “denting” has been applied to the secondary effects which include:

1. Tube diameter reduction

2. Tube support plate hole dilation

3. Tube support plate flow hole distortion, flow slot hourglassing

4. Tube support plate expansion

5. Tube leakage

6. Wrapper distortion

The mechanism which produces the effects cited involves an acid chloride environment in the tube crevices. In sequence, the process appears to occur as follows:

The crevice between the tube and the support plate is blocked as a result of deposition of chemical species present in the bulk water, including phosphate compounds, secondary system corrosion products and minimal tube corrosion products. Once plugged, the annulus provides a site for concentration of various nominally soluble contaminants, such as chlorides, sulfates, etc. Recent studies indicate that in the absence of nonvolatile, alkalizing species, there may exist the potential for production of an acid solution by hydrolysis of such compounds as magnesium chloride, nickel phosphate, cupric chloride, various ferrrous salts, etc. In an acid chloride solution, the corrosion film on the carbon steel is converted from protective in character, to a thick, non-protective oxide of high density which assumes a laminar configuration subject to disruption due to the volume mismatch between the oxide and the base metal. The buildup of the thick oxide in the nominal 14 mil radial gap between the tube and the support plate causes sufficient force to be exerted against the tube to cause plastic deformation locally and correspondingly dilation of the tubehole in the plate. The transmission of these forces can cause distortion of the circulation holes in the plate (both the flow holes between the tubes and the central flow slots between the inlet and outlet halves of the tube bundle). In the most extreme cases as corrosion proceeds and in-plate forces accumulate, the entire plate increases in diameter and the ligaments between the holes in the plate may break. Ovalization of the tubes at the intersections results in high strains, leading to tensile stress on the tube ID and possible leakage by intergranular stress assisted cracking. A similar result may be induced at the apex of the first row (i.e., the smallest radius) U-bend if sufficient distortion of the top support plate flow slots occurs, resulting in leg displacement, ovalization, and high strains. Development to this stage presupposes condenser leakage which results in chloride contamination of the steam generator liquid.

Approximately 100 tubes in the Preheat section of the Unit 1 and Unit 2 steam generators have expanded sections at the “B” and “D” support plate elevations. These tubes have reduced nominal clearances at these support plates. The denting phenomena has been investigated for expanded tubes and it has been found that they are not adversely affected. (See reference 4)

The tube leakage and support plate effects do not pose a safety problem with respect to release of radioactivity or effects on accident calculations, but the frequency of leakage and resultant repair shutdowns does present an economic concern to the operators. The utilization of preventive plugging, therefore, serves to maintain availability and to permit orderly planning for long-term corrective action.

The occurrence of denting has thus far been associated exclusively with plants having a history of chloride contamination due to condenser leakage. Moreover, it has recently been noted that Maine Yankee and Millstone Point 2, non-Westinghouse plants which have used AVT exclusively, have apparently incurred denting also; sea water is used for cooling the condensers at both of these plants.

Research into the causes of denting was initiated shortly after the discovery of the denting condition. Initially, dented tubes were removed for laboratory examination. Subsequently tube support plate samples containing sections of tubing were also removed for analysis from operating plants.

The initial hard data on the nature of the denting phenomenon were derived from these tube/support plate samples which revealed the thick oxide buildup, the tube diameter reduction, and chemical makeup of the crevice-filling materials. It was demonstrated that there was only minor corrosive attack on the tube material, approximately 0-2 mil circumferential thinning, and that the crevice contained a thick layer of almost pure magnetite (Fe_30_4); other chemical constituents included Inconel-metal-phosphate corrosion products close to the tube, and general secondary system contaminants between the Fe_30_4 and the phosphate layer. There was evidence of nickel and copper deposits and the oxide was laced with chlorides.

Armed with those general observations, a series of crevice-with- contaminants tests geometries were evaluated; denting was produced first in reverse as “bulging” when a carbon steel plug was inserted into an Inconel tube to form the crevice; later heated crevice assemblies with heat transfer were shown to be effective dent simulators; finally denting in model boilers equipped with plant-type geometrical configurations was demonstrated. While pure, uncontaminated AVT environments have to date been found to be innocuous, it has been shown that the PO_4 to AVT transition was unnecessary to initiate the denting process. Only the presence of acid chloride solutions has been found to be common factor. Nickel chloride, ferrous or cupric chloride solutions have been shown to be corrosive, and have also produced measurable denting. Thus far, test data indicate that phosphates, calcium hydroxide, zinc oxide and borates seem to retard the dent process; morpholine, among the common volatile amines, shows a beneficial effect on the corrosion rate of carbon steel.

Model boiler tests have been used to evaluate the adequacy of the AVT chemistry specifications adopted in 1974. With one significant alteration, the specifications appear to be adequate to preserve tube integrity: the frequency and the length of time above the chloride limit for normal operation (0.15 ppm) must be limited. Westinghouse is working to prepare a uniform specification to be applied to all plants, which will limit the chloride concentration, the number of consecutive days beyond the normal specification, and the number of incidents per year.

As has been discussed, tube denting is a result of support plate corrosion products compressing the tube while dilating the tube hole. Therefore, measures to inhibit denting concentrate on removing the corrosion mechanisms, medium or materials.

The Comanche Peak steam generators are of the preheat design. The water entering the preheater will be of feedwater quality and any impurities contained therein will not be subject to concentration due to the absence of recirculation. This and thermal-hydraulic characteristics minimize the potential for chemical hideout in the preheater. Since sludge may still settle out at the tubesheet elevation outside the preheater blowdown, pipes have been designed to achieve

maximum removal of the sludge from the steam generators. Should condenser in-leakage occur, specific continuous corrective actions will be taken to minimize its impact.

Operating experience, verified in numerous steam generator inspections, indicates that the tube degradation associated with phosphate water treatment is not occurring where only AVT has been utilized. Adherence to the AVT chemical specifications and close monitoring of the condenser integrity will assure the continued good performance of the steam generator tubing.

5.4.2B.6 Quality Assurance

The steam generator quality assurance program is given in Table 5.4-4.

Radiographic inspection and acceptance standard shall be in accordance with the requirements of Section III of the ASME Code.

Liquid penetrant inspection is performed on weld deposited tubesheet cladding, channel head cladding, and tube-to-tubesheet weldments. Liquid penetrant inspection and acceptance standards are in accordance with the requirements of Section III of the ASME Code.

Magnetic particle inspection is performed on the tubesheet forging, channel head casting, nozzle forgings, and the following weldments:

1. Nozzles to shell.

2. Support brackets.

3. Instrument connection (primary and secondary)

4. Temporary attachments after removal.

5. All accessible pressure containing welds after hydrostatic test.

Magnetic particle inspection and acceptance standard are in accordance with requirements of Section III of the ASME Code.

An ultrasonic test is performed on the tubesheet forging, tubesheet cladding, secondary shell and head plate and nozzle forging.

The heat transfer tubing is subjected to eddy current and ultrasonic tests.

Hydrostatic tests are performed in accordance with Section III of the ASME Code.

In addition, the heat transfer tubes shall be subjected to a hydrostatic test pressure prior to installation into the vessel which is not less than 1.25 times the primary side design pressure.

5.4.3 REACTOR COOLANT PIPING

5.4.3.1 Design Bases

The RCS piping is designed and fabricated to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions. Stresses are maintained within the limits of Section III of the ASME Code. Code and material requirements are provided in Section 5.2.

Materials of construction are specified to minimize corrosion/erosion and ensure compatibility with the operating environment.

The piping in the RCS is Safety Class 1 and is designed and fabricated in accordance with the ASME Code, Section III, Class 1 requirements.

Stainless steel pipe conforms to ANSI B36.19 for sizes 1/2 inch through 12 inches and wall thickness Schedules 40S through 80S. Stainless steel pipe outside of the scope of ANSI B36.19 conforms to ANSI B36.10.

The minimum wall thickness of the loop pipe and fittings are not less than that calculated using the ASME Code, Section III, Class 1 formula of paragraph NB-3641.1(3) with an allowable stress value of 17,550 psi. The CPNPP Unit 1 and 2 pressurizer surge line design utilizes schedule 160 piping with the exception of a one foot section of schedule 140 piping in the Unit 1 pressurizer surge line. The minimum pipe bend radius is 5 nominal pipe diameters; ovality does not exceed 6 percent.

All butt welds, branch connection nozzle welds, and boss welds shall be of a full penetration design.

Processing and minimization of sensitization are discussed in Section 5.2.3.

Flanges conform to ANSI B16.5.

Socket weld fittings and socket joints conform to ANSI B16.11.

Inservice inspection is discussed in Section 5.2.4.

5.4.3.2 Design Description

Principal design data for the reactor coolant piping are given in Table 5.4-5.

Pipe and fittings are cast, seamless without longitudinal welds and electroslag welds, and comply with the requirements of the ASME Code, Section II (Part A and C), Section III, and Section IX.

The RCS piping is specified in the smallest size consistent with system requirements. This design philosophy results in the reactor inlet and outlet piping diameters given in Table 5.4-5. The line between the steam generator and the pump suction is larger to reduce pressure drop and improve flow conditions to the pump suction.

The reactor coolant piping and fittings which make up the loops are austenitic stainless steel. There will be no electroslag welding on these components. All smaller piping which comprise part of the RCS such as the pressurizer surge line, spray and relief line, loop drains and connecting lines to other systems are also austenitic stainless steel. The nitrogen supply line for the pressurizer relief tank is carbon steel. All joints and connections are welded, except for the pressurizer code safety valves, where flanged joints are used. A thermal sleeve is installed on the pressurizer surge nozzle located on the bottom of the pressurizer vessel.

All piping connections from auxiliary systems are made above the horizontal centerline of the reactor coolant piping, with the exception of:

1. Residual heat removal pump suction lines, which are 45 degrees down from the horizontal centerline. This enables the water level in the RCS to be lowered in the reactor coolant piping while continuing to operate the Residual Heat Removal System, should this be required for maintenance.

2. Loop drain lines and the connection for temporary level measurement of water in the RCS during refueling and maintenance operation.

3. The differential pressure taps for flow measurement, which are downstream of the steam generators on the first 90 degree elbow.

4. The pressurizer surge line, which is attached at 45 degrees above the horizontal centerline.

5. The 3 inch branch connections to accommodate the 1 1/2 inch cold leg safety injection lines are located on the horizontal centerline.

6. Two of the three taps in each resistance temperature detector hot leg connection.

Penetrations into the coolant flow path are limited to the following:

1. The spray line inlet connections extend into the cold leg piping in the form of a scoop so that the velocity head of the reactor coolant loop flow adds to the spray driving force.

2. The reactor coolant sample system taps protrude into the main stream to obtain a representative sample of the reactor coolant.

3. Hot leg thermowells to accommodate in line narrow range RTDs.

4. The wide range temperature detectors are located in resistance temperature detector wells that extend into both the hot and cold legs of the reactor coolant pipes.

5. Cold leg RTD thermowells are for the fast response T_{cold} measurement.

In the previous design, a hot leg temperature measurement was made in the hot leg RTD manifold. This was combined with a cold leg temperature measurement in the cold leg RTD manifold to provide a ΔT signal which was used as an indication of reactor power in the

protection system. The ΔT measurement was also used off-line in conjunction with a secondary system power measurement to perform a calorimetric calculation of primary system flow rate.

Two cold leg RTD thermowells in each loop are installed to replace the cold leg RTD manifold. The cold leg bypass nozzles and crossover leg bypass return nozzles are installed in the main loop piping; however, all of these connections have been plugged and are not used.

In the new configuration as discussed in Section 7.2.1.1.4.2, there are four N-16 detectors mounted externally on each hot leg piping. The two upstream detectors are used to provide indication of reactor power for use in the protection system and can also be used by the transit time flow meter to measure reactor coolant flow. The two down stream detectors are only used to provide an input to the transit time flow meter. There are narrow range hot leg RTDs in Unit 1 only for this new configuration.

The RCS piping includes those sections of piping interconnecting the reactor vessel, steam generator, and reactor coolant pump. It also includes the following:

1. Charging line and alternate charging line from the system isolation valve up to the branch connections on the reactor coolant loop.

2. Letdown line and excess letdown line from the branch connections on the reactor coolant loop to the system isolation valve.

3. Pressurizer spray lines from the reactor coolant cold legs to the spray nozzle on the pressurizer vessel.

4. Residual heat removal lines to or from the reactor coolant loops up to the designated check valve or isolation valve.

5. Safety injection lines from the designated check valve to the reactor coolant loops.

6. Accumulator lines from the designated check valve to the reactor coolant loops.

7. Drain, sample[a], and instrument[a] lines to or from the designated isolation valve to or from the reactor coolant loops.

8. Pressurizer surge line from one reactor coolant loop hot leg to the pressurizer vessel inlet nozzle.

9. Pressurizer spray scoop, sample connection[a] with scoop, reactor coolant temperature element installation boss, and the temperature element well itself.

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a. Lines with a 3/8 inch flow restricting orifice qualify as Safety Class 2; in the event of a break in one of these Safety Class 2 lines, the normal makeup system is capable of providing makeup flow while maintaining pressurizer water level.

10. All branch connection nozzles attached to reactor coolant loops.

11. Pressure relief lines from nozzles on top of the pressurizer vessel up to and through the power operated pressurizer relief valves and pressurizer safety valves.

12. Seal injection water and labyrinth differential pressure lines to or from the reactor coolant pump inside reactor Containment.

13. Auxiliary spray line from the isolation valve to the pressurizer spray line header.

14. Sample lines[a] from pressurizer to the isolation valve.

Details of the materials of construction and codes used in the fabrication of reactor coolant piping and fittings are discussed in Section 5.2.

5.4.3.3 Design Evaluation

Piping load and stress evaluation for normal operating loads, seismic loads, blowdown loads, and combined normal, blowdown and seismic loads is discussed in Section 3.9(N).

5.4.3.3.1 Material Corrosion/Erosion Evaluation

The water chemistry is selected to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications.

The design and construction are in compliance with the ASME Code, Section XI, Subarticle IWA-1500. Pursuant to this, all pressure containing welds out to the second valve that delineates the RCS boundary are available for examination with removable insulation.

Components constructed with stainless steel will operate satisfactorily under normal plant chemistry conditions in pressurized water reactor system, because chlorides, fluorides, and particularly oxygen, are controlled to very low levels (see Section 5.2.3).

Periodic analysis of the coolant chemical composition is performed to monitor the adherence of the system to desired reactor coolant water quality listed in Table 5.2-5. Maintenance of the water quality to minimize corrosion is accomplished using the Chemical and Volume Control System and Sampling System which are described in Chapter 9.

5.4.3.3.2 Sensitized Stainless Steel

Sensitized stainless steel is discussed in Section 5.2.3.

5.4.3.3.3 Contaminant Control

Contamination of stainless steel and Inconel by copper, low melting temperature alloys, mercury and lead is prohibited. Colloidal graphite is the only permissible thread lubricant.

Prior to application of thermal insulation, the austenitic stainless steel surfaces are cleaned and analyzed to a halogen limit of 0.0015 mg Cl/dm^2 and 0.0015 F/dm^2.

5.4.3.4 Tests and Inspections

The RCS piping quality assurance program is given in Table 5.4-6.

Volumetric examination is performed throughout 100 percent of the wall volume of each pipe and fitting in accordance with the applicable requirements of Section III of the ASME Code for all pipe 27-1/2 inches and larger. All unacceptable defects are eliminated in accordance with the requirements of the same section of the code.

A liquid penetrant examination is performed on both the entire outside and inside surfaces of each finished fitting in accordance with the criteria of the ASME Code, Section III. Acceptance standards are in accordance with the applicable requirements of the ASME Code, Section III.

The pressurizer surge line conforms to SA-376, Grade 304, 304N, or 316 with supplementary requirements S2 (transverse tension tests), and S6 (ultrasonic test). The S2 requirement applies to each length of pipe. The S6 requirement applies to 100 percent of the piping wall volume.

The end of pipe sections, branch ends and fittings are machined back to provide a smooth weld transition adjacent to the weld path.

5.4.4 MAIN STEAM LINE FLOW RESTRICTOR

5.4.4.1 Design Basis

The outlet nozzle of the steam generator is provided with a flow restrictor designed to limit steam flow in the unlikely event of a break in the main steam line. A large increase in steam flow will create a backpressure which limits further increase in flow. Several protective advantages are thereby provided: rapid rise in Containment pressure is prevented, the rate of heat removal from the reactor coolant is kept within acceptable limits, thrust forces on the main steam line piping are reduced, and most important, stresses on internal steam generator components, particularly the tubesheet and tubes, are limited. The restrictor is also designed to minimize the unrecovered pressure loss across the restrictor during normal operation.

5.4.4.2 Design Description

The flow restrictor (Figure 5.4-5) consists of seven Inconel (ASME-SB-163) venturi inserts which are inserted into the holes in a integral steam outlet low alloy steel forging. The inserts are arranged with one venturi at the centerline of the outlet nozzle and the other six equally spaced around it. After insertion into the low alloy steel forging holes, the inconel venturi nozzles are welded to the inconel cladding on the inner surface of the forging.

5.4.4.3 Design Evaluation

The flow restrictor design has been sufficiently analyzed to assure its structural adequacy. The equivalent throat diameter of the steam generator outlet is 16 inches, and the resultant pressure drop through the restrictor at 100 percent steam flow is approximately 3.4 psi.

This is based on a design flow rate f 3.78 x 10^6 lb/hr. Materials of construction and manufacturing of the flow restrictor are in accordance with Section III of the ASME Code.

5.4.4.4 Tests and Inspections

Since the restrictor is not a part of the steam system boundary, no tests and inspection beyond those during fabrication, are anticipated.

5.4.5 MAIN STEAM LINE ISOLATION SYSTEM

The Main Steam Line Isolation System is described in Sections 6.2.4 and 10.3.

5.4.6 REACTOR CORE ISOLATION COOLING SYSTEM

This section is not applicable to the Comanche Peak Nuclear Power Plant (CPNPP).

5.4.7 RESIDUAL HEAT REMOVAL SYSTEM

The Residual Heat Removal System (RHRS) transfers heat from the RCS to the Component Cooling Water System to reduce the temperature of the reactor coolant to the cold shutdown temperature at a controlled rate during the second part of normal plant cooldown and maintains this temperature until the plant is started up again.

Parts of the RHRS also serve as parts of the ECCS during the injection and recirculation phases of a LOCA (see Section 6.3).

The RHRS also is used to transfer refueling water between the refueling cavity and the Refueling Water Storage Tank at the beginning and end of the refueling operations.

Nuclear plants employing the same RHRS design as the CPNPP are given in Section 1.3.

5.4.7.1 Design Bases

RHRS design parameters are listed in Table 5.4-7.

For normal plant cooldowns, the RHRS is required to cool the RCS to a temperature adequate for refueling or maintenance in a time that is consistent with refueling or maintenance operations. The RHRS is designed to be placed in operation approximately 4 hours after reactor shutdown when the temperature and pressure of the RCS are approximately 350°F and 425 psig, respectively. Assuming that two heat exchangers and two pumps are in service and that each heat exchanger is supplied with component cooling water at design flow and maximum temperature, the RHRS is designed to reduce the temperature of the reactor coolant from 350°F to 140°F within 28 hours. The time required, under these conditions, to reduce reactor coolant temperature from 350°F to 212°F is less than 4 hours. The heat load handled by the RHRS during the cooldown transient includes residual and decay heat from the core and reactor coolant pump heat. The design heat load is based on the ANSI/ANS-5.1-1979 American National Standard for Decay Heat in Light Water Reactors.

For abnormal plant cooldowns, the RHRS is required to cool the RCS from hot shutdown (350°F) to cold shutdown (200°F) in a reasonable period of time, assuming the most limiting single failure. See Appendix 5A for an evaluation of compliance with Branch Technical Position RSB 5-1.

In the event of a fire, the RHRS is required to cool the RCS from hot shutdown to cold shutdown as described in the Fire Protection Report.

In the event of a design basis accident in one unit, the other unit is required to be capable of an orderly shutdown and cooldown. [GDC-5]

The RHRS is also required to cool the RCS from hot standby to cold shutdown in less than 24 hours starting 12 hours after reactor shutdown assuming only one heat exchanger and pump are in service and the Safe Shutdown Impoundment is conservatively assumed at 102°F. This ensures the RHRS is capable of satisfying action times in the Technical Specifications.

The RHRS is designed to be isolated from the RCS whenever the RCS pressure exceeds the RHRS design pressure. The RHRS is isolated from the RCS on the suction side by two motor operated valves in series on each suction line. Each motor operated valve is interlocked to prevent its opening if RCS pressure is greater than 425 psig. The RHRS is isolated from the RCS on the discharge side by two check valves in each return line. Also provided on the discharge side is a normally open motor operated valve downstream of each RHRS heat exchanger. (These check valves and motor operated valves are not considered part of the RHRS; they are shown as part of the ECCS; see Figure 6.3-1).

Each inlet line to the RHRS is equipped with a pressure relief valve designed to relieve the combined flow of all the charging pumps at the relief valve set pressure. These relief valves also protect the system from inadvertent overpressurization during plant cooldown or startup. Each discharge line from the RHRS to the RCS is equipped with a pressure relief valve designed to relieve the maximum possible backleakage through the valves isolating the RHRS from the RCS.

The RHRS is designed for a single nuclear power unit and is not shared among nuclear power units.

The RHRS is designed to be fully operable from the Control Room for normal operation following the restoration of power to both inlet motor operated valves in each suction line. Power is removed to prevent inadvertent or spurious actuation. Control Room manual operations required of the operator are: opening the suction isolation valves, positioning the flow control valves downstream of the RHRS heat exchangers, and starting the residual heat removal pumps. By nature of its redundant two train design, the RHRS is designed to accept all major component single failures with the only effect being an extension in the required cooldown time. For two low probability electrical system single failures, i.e., failure in the suction isolation valve interlock circuitry, or diesel generator failure in conjunction with loss of offsite power, limited operator action outside the Control Room is required to open the suction isolation valves. Although Westinghouse considers it to be of low probability, spurious operation of a single motor operated valve can be accepted without loss of function as a result of the redundant two train design.

Missile protection, protection against dynamic effects associated with the postulated rupture of piping, and aseismic design are discussed in Sections 3.5, 3.6N and 3.7N respectively.

5.4.7.2 System Design

5.4.7.2.1 Schematic Piping and Instrumentation Diagrams

The RHRS, as shown in Figures 5.4-6 and 5.4-7, consists of two residual heat exchangers, two residual heat removal pumps, and the associated piping, valves, and instrumentation necessary for operational control. The inlet lines to the RHRS are connected to the hot legs of two reactor coolant loops, while the return lines are connected to the cold legs of each of the reactor coolant loops. These return lines are also the ECCS low head injection lines (see Figure 6.3-1).

The RHRS suction lines are isolated from the RCS by two motor operated valves in series and a relief valve, all located inside the Containment. Each discharge line is isolated from the RCS by two check valves located inside the Containment and by a normally open motor operated valve located outside the containment. (The check valves and the Motor operated valve on each discharge line are not part of the RHRS; these valves are shown as part of the ECCS, see Figure 6.3-1).

During RHRS operation, reactor coolant flows from the RCS to the residual heat removal pumps, through the tube side of the residual heat exchangers, and back to the RCS. The heat is transferred to the component cooling water circulating through the shell side of the residual heat exchangers.

Coincident with operation of the RHRS, a portion of the reactor coolant flow may be diverted from downstream of the residual heat exchangers to the Chemical and Volume Control System low pressure letdown line for cleanup and/or pressure control. By regulating the diverted flow rate and the charging flow, the RCS pressure may be controlled. Pressure regulation is necessary to maintain the pressure range dictated by the fracture prevention criteria requirements of the reactor vessel and by the number 1 seal differential pressure and net positive suction head requirements of the reactor coolant pumps.

The RCS cooldown rate is manually controlled by regulating the reactor coolant flow through the tube side of the residual heat exchangers. A line containing a flow control valve bypasses each residual heat exchanger and is used to maintain a constant return flow to the RCS. Instrumentation is provided to monitor system pressure, temperature and total flow.

The RHRS is also used for filling the refueling cavity before refueling. After refueling operations, water is pumped back to the Refueling Water Storage Tank until the water level is brought down to the flange of the reactor vessel. The remainder of the water is removed via a drain connection at the bottom of the refueling canal.

When the RHRS is in operation, the water chemistry is the same as that of the reactor coolant. Provision is made for the Process Sampling System to extract samples from the flow of reactor coolant downstream of the residual heat exchangers. A local sampling point is also provided on each residual heat removal train between the pump and heat exchangers.

The RHRS functions in conjunction with the high head portion of the ECCS to provide injection of borated water from the Refueling Water Storage Tank into the RCS cold legs during the injection phase following a LOCA.

In its capacity as the low head portion of the ECCS, the RHRS provides long term recirculation capability for core cooling following the injection phase of the LOCA. This function is accomplished by aligning the RHRS to take fluid from the Containment sump, cool it by circulation through the residual heat exchangers, and supply it to the core directly as well as via the centrifugal charging pumps and safety injection pumps.

The use of the RHRS as part of the ECCS is more completely described in Section 6.3.

The RHR pumps, in order to perform their ECCS function, are interlocked to start automatically on receipt of a safety injection signal (see Section 6.3).

The RHR suction isolation valves in each inlet line from the RCS are separately interlocked to prevent both their being opened when RCS pressure is greater than 425 psig. This interlock is described in more detail in Sections 5.4.7.2.4 and 7.6.2.

The RHR suction isolation valves are also interlocked to prevent their being opened unless the isolation valves in the following lines are closed:

1. Recirculation lines from the residual heat exchanger outlets to the suctions of the safety injection pumps and centrifugal charging pumps.

2. Residual heat removal pump suction line from the Refueling Water Storage Tank.

3. Residual heat removal pump suction line from the Containment sump.

The motor operated valves in the RHR miniflow bypass lines are interlocked to open when the RHR pump discharge flow is less than 500 gpm and close when the flow exceeds 1000 gpm. This interlock is also described in more detail in Section 5.4.7.2.4. The logic circuitry for the interlock is shown in Figure 5.4-20.

5.4.7.2.2 Equipment and Component Descriptions

The materials used to fabricate RHRS components are in accordance with the applicable code requirements. All parts of components in contact with borated water are fabricated or clad with austenitic stainless steel or equivalent corrosion resistant material. Component parameters are given in Table 5.4-8.

Residual Heat Removal Pumps

Two pumps are installed in the RHRS. Component cooling water is supplied to RHR pump seal coolers under all modes of plant operation. The RHR pumps operate during startup, cooldown, and cold shutdown operations, and during safeguards operations.

The pumps are sized to deliver reactor coolant flow through the residual heat exchangers to meet the plant cooldown requirements. The use of two separate residual heat removal trains assures that cooling capacity is only partially lost should one pump become inoperative.

The residual heat removal pumps are protected from overheating and loss of suction flow by miniflow bypass lines that assure flow to the pump suction. A valve located in each miniflow line is regulated by a signal from the flow transmitters located in each pump discharge header. The

control valves open when the residual pump discharge flow is less than 500 gpm and close when the flow exceeds 1000 gpm.

Each RHR train is provided with control board position indication of the miniflow and suction valves, and a low flow alarm to alert the operator to the inadvertent closure of a suction valve on a running RHR pump. A pressure sensor in each pump discharge header provides a signal for an indicator in the Control Room. A high pressure alarm is also actuated by the pressure sensor.

The two pumps are vertical, centrifugal units with mechanical seals on the shafts. All pump surfaces in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant material.

The residual heat removal pumps also function as the low head safety injection pumps in the ECCS (see Section 6.3 for further information and for the residual heat removal pump performance curves).

Residual Heat Exchangers

Two residual heat exchangers are installed in the system. The heat exchanger design is based on heat load and temperature differences between reactor coolant and component cooling water existing 28 hours after reactor shutdown when the temperature difference between the two systems is small.

The installation of two heat exchangers in separate and independent residual heat removal trains assures that the heat removal capacity of the system is only partially lost if one train becomes inoperative.

The residual heat exchangers are of the shell and U-tube type. Reactor coolant circulates through the tubes, while component cooling water circulates through the shell. The tubes are welded to the tubesheet to prevent leakage of reactor coolant.

The residual heat exchangers also function as part of the ECCS (see Section 6.3).

Residual Heat Removal System Valves

Valves that perform a modulating function are equipped with two sets of packings and an intermediate leakoff connection that discharges to the drain header.

Manual and motor operated valves typically have backseats to facilitate repacking. Leakage connections are provided where required by valve size and fluid conditions.

5.4.7.2.3 System Operation

Reactor Startup

Generally, while at cold shutdown condition, decay heat from the reactor core is being removed by the RHRS. The number of pumps and heat exchangers in service depends upon the heat load at the time.

At initiation of the plant startup, the RCS is completely filled, and the pressurizer heaters are energized. The RHRS is operating and is connected to the Chemical and Volume Control System via the low pressure letdown line to control reactor coolant pressure. During this time, the RHRS acts as an alternate letdown path. The manual valves downstream of the residual heat exchangers leading to the letdown line of the Chemical and Volume Control System are opened to permit letdown flow to CVCS. The normal letdown pressure control valve in CVCS is then adjusted to regulate letdown flow and RCS pressure.

After the reactor coolant pumps are started, the residual heat removal pumps may continue to run to assist in controlling the heatup rate. The RHRS pumps are stopped when RCS pressure is increased to approximately 400 psig, but pressure control via the RHRS and the low pressure let down line is continued until the pressurizer steam bubble is formed. Indication of steam bubble formation is provided in the Control Room by the damping out of the RCS pressure fluctuations, and by pressurizer level indication. The RHRS is then isolated from the RCS (prior to reaching 350°F) and the system pressure is controlled by normal letdown and the pressurizer spray and pressurizer heaters.

Power Generation and Hot Standby Operation

During power generation and hot standby operation, the RHRS is not in service but is aligned for operation as part of the ECCS.

Reactor Cooldown

Reactor cooldown is defined as the operation which brings the reactor from no-load temperature and pressure to cold conditions.

The initial phase of reactor cooldown is accomplished by transferring heat from the RCS to the Steam and Power Conversion System through the use of the steam generators.

When the reactor coolant temperature and pressure are reduced to approximately 350°F and 425 psig, approximately 4 hours after reactor shutdown, the second phase of cooldown starts with the RHRS being placed in operation.

Startup of the RHRS includes a warmup period during which time reactor coolant flow through the heat exchangers is limited to minimize thermal shock. The rate of heat removal from the reactor coolant is manually controlled by regulating the coolant flow through the residual heat exchangers. By adjusting the control valves downstream of the residual heat exchangers the mixed mean temperature of the return flows is controlled. Coincident with the manual adjustment, each heat exchanger bypass valve is regulated to give the required total flow.

Provisions exist to isolate the RHR lines and restore the ECCS capability for core cooling should a leak or rupture develop during cooldown (below 400 psig). Any leakage of the RHR System piping would be expected to occur when the System is initially pressurized at 400 psig. The RCS is at this time under manual control by the reactor operator, who is monitoring the pressurizer level and the RCS loop pressure. Any significant leakage from the RHR System would be immediately detected. Upon detection, the operator would isolate the RHR System and identify the location and cause. Since decay heat generation four hours after shutdown is about 1.2% of

full power, the RCS fluid temperature is at about 350^{o}F, and the core stored energy is essentially removed, the operator would have ample time to isolate the RHR loop.

The reactor cooldown rate is limited by RCS equipment cooling rates based on allowable stress limits, as well as the operating temperature limits of the Component Cooling Water System. As the reactor coolant temperature decreases, the reactor coolant flow through the residual heat exchangers is increased by adjusting the control valve in each heat exchanger's tube side outlet line.

As cooldown continues, the pressurizer is filled with water and the RCS is operated in the water solid condition.

At this stage, pressure control is accomplished by regulating the charging flow rate and the rate of letdown from the RHRS to the Chemical and Volume Control System.

After the reactor coolant pressure is reduced and the temperature is 140°F or lower, the RCS may be opened for refueling or maintenance.

The potential for exceeding the allowable cooldown rate has been analyzed. The maximum cooldown rate which can result if both RHR flow control valves and both RHR bypass valves all simultaneously fail in such a manner as to permit maximum flow through the RHR heat exchangers depends on several factors including the RHR flow rate, the component cooling water system flow rates and temperatures, and other heat loads on the component cooling water system. (This simultaneous failure is considered to be a low probability event considering the few hours a year when it could cause any effect).

One of the key factors is the RCS temperature, since the heat removal rate depends on the temperature differential between the RHR (RCS) flow and the component cooling water flow in the RHR heat exchanger. Typically, it is impossible to maintain a cooldown rate even as big as 50°F/hr when the RCS temperature is less than 250°F, even with the maximum flow through the RHR heat exchangers. Even if maximum flow through the RHR heat exchangers was experienced at the instant of initiating RHR operation and no operator actions was taken, it is unlikely that the cooldown would exceed 100°F over the first hour. The maximum possible cooldown rate for the period from 350°F to 250°F would not exceed 200°F/hr.

Calculations have been performed which show that, from a stress standpoint, a cooldown rate greater than 200°F/hr is acceptable for such a hypothetical cooldown from 350° to 250°F even though it is difficult to maintain a cooldown rate of 50°F/hr at or below an RCS temperature of 250°F. Although such a hypothetical cooldown event is acceptable from a stress standpoint, assuming no operator action, it should be noted that the operator can significantly limit the maximum possible cooldown rate by merely stopping one of the RHR pumps. See Table 5.4-17.

Refueling

Both residual heat removal pumps are utilized during refueling to pump borated water from the Refueling Water Storage Tank to the refueling cavity. During this operation, the isolation valves in the inlet lines of the RHRS are closed, and the isolation valves to the Refueling Water Storage Tank are opened.

The reactor vessel head is lifted slightly. The refueling water is then pumped into the reactor vessel through the normal RHRS return lines and into the refueling cavity through the open reactor vessel. The reactor vessel head is gradually raised as the water level in the refueling cavity increases. After the water level reaches the normal refueling level, the inlet isolation valves are opened, the Refueling Water Storage Tank supply valves are closed, and residual heat removal is resumed.

During refueling, the RHRS is maintained in service with the number of pumps and heat exchangers in operation as required by the heat load.

Following refueling, the residual heat removal pumps are used to drain the refueling cavity to the top of the reactor vessel flange by pumping water from the RCS to the Refueling Water Storage Tank.

The residual heat removal pumps may also be used during filling of Safety Injection Accumulators.

5.4.7.2.4 Control

Each inlet line to the RHRS is equipped with a pressure relief valve sized to relieve the combined flow of all the charging pumps at the relief valve set pressure. Sufficient capacity in RHR relief valves is available to also relieve thermal expansion. These relief valves also protect the system from inadvertent overpressurization during plant cooldown or startup. Each valve has a relief flow capacity of 900 gpm at a set pressure of 450 psig. An analysis has been conducted to confirm the capability of the RHRS relief valve to prevent overpressurization in the RHRS. All credible events were examined for their potential to overpressurize the RHRS. These events included normal operating conditions, infrequent transients, and abnormal occurrences. The analysis confirmed that one relief valve has the capability to keep the RHRS maximum pressure within code limits.

Each discharge line from the RHRS to the RCS is equipped with a pressure relief valve to relieve the maximum possible backleakage through the valves separating the RHRS from the RCS. Technical specifications places maximum limits on RCS leakage. Further, the technical specifications require the plant to be shutdown within specified time periods if these values are exceeded. Each valve has a relief flow capacity of 20 gpm at a set pressure of 600 psig; therefore, even if it were conservatively assumed that all RCS leakage was in one RHR train the relief value still provides significant margin. These relief valves are located in the ECCS (see Figure 6.3-1).

The fluid discharged by the suction side relief valves is collected in the pressurizer relief tank. The fluid discharged by the discharge side relief valves is collected in the recycle holdup tank of the Boron Recycle System.

The design of the RHRS includes two motor operated gate isolation valves in series on each inlet line between the high pressure RCS and the lower pressure RHRS. They are closed during normal operation and are only opened for residual heat removal during a plant cooldown after the RCS pressure is reduced to 425 psig or lower and RCS temperature is reduced to approximately 350°F. During a plant startup the inlet isolation valves are shut after drawing a bubble in the pressurizer and prior to increasing RCS pressure above 600 psig. These isolation valves are

provided with a “prevent-open” interlock which is designed to prevent possible exposure of the RHRS to normal RCS operating pressure.

The two inlet isolation valves in each residual heat removal subsystem are separately and independently interlocked with pressure signals to prevent being opened when RCS pressure is greater than RHRS operational pressure.

The interlock signal provided to the isolation valve closest to the RCS is independent and diverse from the interlock signal provided to the isolation valves closest to the RHRS.

Overpressure protection is provided for the piping between each pair of RHR isolation valves via check valves in a bypass line. Should a pressure build-up occur either from water trapped between these normally closed inner and outer isolation valves or from thermal expansion of the water in this section of line due to a rapid heat-up of containment (e.g. following a postulated LOCA or steam break), pressure is relieved through these check valves (See Figure 5.4-6).

The use of two independently powered motor operated valves in each of the two inlet lines, along with two independent pressure interlock signals for each function assures a design which meets applicable single failure criteria. Not only more than one single failure but also different failure mechanisms must be postulated to defeat the function of preventing possible exposure of the RHRS to normal RCS operating pressure. These protective interlock designs, in combination with plant operating procedures, provide diverse means of accomplishing the protective function.

For a discussion of the function of the RHR suction line isolation valve arrangement, see FSAR Section 6.2.4.1.3.5. For further information on the instrumentation and control features, see Section 7.6.2.

The RHR inlet isolation valves are provided with red-green position indicator lights on the main control board.

Isolation of the low pressure RHRS from the high pressure RCS is provided on the discharge side by two check valves in series. These check valves are located in the ECCS and their testing is described in Section 6.3.4.2.

The motor-operated valves in the mini-flow bypass lines between the RHR pump suction and discharge is normally open. These valves are interlocked to flow transmitters in the pump discharge lines to close when the RHR pump discharge flow goes above an upper limit, and reopen when the pump discharge flow fails below a minimum value. The interlock ensures that the flow through the RHR pump will be sufficient to cool the pump when the pressure in the lines to which the pump discharge flow is directed is greater than pump discharge pressure. The margin between the opening and closing signals prevents valve operator cycling due to flow restrictions. The separation of this interlock is in accordance with IEEE 384-1974. The Train A interlock is electrically independent from the Train B interlock. A single random electrical failure of the interlock in one train will not prevent operation of the interlock in the redundant train. In addition, the interlock is environmentally and seismically qualified to the appropriate criteria.

5.4.7.2.5 Applicable Codes and Classifications

The entire RHRS is designed as Nuclear Safety Class 2. Component codes and classifications are given in Section 3.2.

5.4.7.2.6 System Reliability Considerations

General Design Criterion 34 requires that a system to remove residual heat be provided. The safety function of this system is to transfer fission product decay heat and other residual heat from the core at a rate sufficient to prevent fuel or pressure boundary design limits from being exceeded. Safety grade systems are provided in the plant design, both NSSS scope and balance of plant scope, to perform this safety function. The NSSS scope safety grade systems which perform this function, for all plant conditions except a LOCA, are the RCS and steam generators, which operate in conjunction with the Auxiliary Feedwater System, the steam generator safety valves, and the steam generator power operated relief valves; and the RHRS which operates in conjunction with the Component Cooling Water System and the Service Water System. The balance of plant scope safety grade systems which perform this function, for all plant conditions except LOCA, are the Auxiliary Feedwater System, the steam generator safety valves, and the steam generator power operated relief valves, which operate in conjunction with the RCS and the steam generators; and the component cooling water and service water systems, which operate in conjunction with the RHRS. For LOCA conditions, the safety grade system which performs the function of removing residual heat from the reactor core is the ECCS, which operates in conjunction with the Component Cooling Water System and the Service Water System.

The RHRS is provided with two residual heat removal pumps, and two residual heat removal heat exchangers arranged in two separate, independent flow paths. To assure reliability, each residual heat removal pump is connected to a different vital bus. Each residual heat removal train is isolated from the RCS on the suction side by two motor operated valves in series. Each motor operated valve receives power via a separate motor control center and the two valves in series in each train receive their power from a different vital bus. Each suction isolation valve is also interlocked to prevent exposure of the RHRS to the normal operating pressure of the RCS (see Section 5.4.7.2.4).

RHRS operation for normal conditions and for major failures is accomplished completely from the Control Room following the restoration of power to both inlet motor operated valves in each suction line. Power is removed to prevent inadvertent or spurious actuation. The redundancy in the RHRS design provides the system with the capability to maintain its cooling function even with major single failures, such as failure of a residual heat removal pump, valve, or heat exchanger since the redundant train can be used for continued heat removal. Consequences of the loss of component cooling water flow to RHR pumps are discussed in Section 9.2.2.

Although such major system failures are within the system design basis, there are other less significant failures which can prevent opening of the residual heat removal suction isolation valves from the Control Room. Since these failures are of a minor nature, improbable to occur, and easily corrected outside the Control Room, with ample time to do so, they have been realistically excluded from the engineering design basis.

Such failures are not likely to occur during the limited time period in which they can have any effect (i.e., when opening the suction isolation valves to initiate RHR operation); however, even if they should occur, they have no adverse safety impact and can be readily corrected. In such a situation, the Auxiliary Feedwater System and steam generator power operated relief valves can be used to maintain the plant at 350°F until the RHRS is made available.

One failure of this type is a failure in the interlock circuitry which is designed to prevent exposure of the RHRS to the normal operating pressure of the RCS (see Section 5.4.7.2.4). In the event of such a failure, RHRS operation can be initiated by defeating the failed interlock through corrective action at the solid State Protection System cabinet or at the individual effected motor control centers.

The other type of failure which can prevent opening the residual heat removal suction isolation valves (8701B and 8702A, as shown in Figure 5.4-6) from the Control Room is a failure of normal electrical power train. Such a failure is extremely unlikely to occur during the few minutes out of a year's operating time during which it can have any consequence. If such an unlikely event should occur, several alternatives are available. The most realistic approach would be to obtain restoration of offsite power, which can be expected to occur in less than 1/2 hour. Other alternatives are to restore the emergency diesel generator to operation or to bring in an alternate power source to valves 8701B and 8702A as described below.

Normally, valve 8701B is supplied via a Train A power supply and 8702A via a Train B power supply. In the event one power supply train becomes unavailable, alternate connections are made as follows:

The description applies to valve 8701B, however, a similar procedure applies to 8702A. Two metal enclosed junction boxes (one for Train A and one for Train B) are connected by rigid steel conduit to a common metal enclosed junction box. Power and control cables from Train A and Train B motor control centers are terminated by female connectors in the Train A and Train B junction boxes respectively.

Train A cables from the valve motor and limit switch are terminated by male cable connectors and routed through the common junction box. Sufficient slack in these cables are provided so that the male connectors can be plugged into the appropriate Train A or Train B female connectors as required. Normally, the connectors are mated in the Train A junction box. When required, cables are unplugged and removed from the Train A junction box and replugged in the Train B junction box.

A combination motor starter, with control switch and indicating lights, provided in the Train B motor control center then permits valve operation from the Train B motor control center.

The only impact of either of the above types of failures is some delay in initiating residual heat removal operation, while action is taken to open the residual heat removal suction isolation valves. This delay has no adverse safety impact because the Auxiliary Feedwater System and steam generator power operated relief valves can be used to maintain the plant at 350° until the RHRS is made available.

A failure mode and effects analysis (FMEA) of the Residual Heat Removal System is provided as Table 5.4-17. Although the FMEA specifically addresses single active mechanical failures in the RHR System, spurious movement of powered components and operator errors by the nature of the system and the FMEA are enveloped in the analysis. Passive failures of non-active components, although not addressed in the FMEA, will affect a single train, due to provisions for isolation of the independent RHR trains.

5.4.7.2.7 Manual Actions

The RHRS is designed to be fully operable from the Control Room for normal operation following the restoration of power to both valves in each of the suction lines. Power is removed to prevent inadvertent or spurious actuation. Control Room manual operations required of the operator are: opening the suction isolation valves, positioning the flow control valves down stream of the RHRS heat exchangers, and starting the residual heat removal pumps.

Manual actions required outside the Control Room under conditions of single failure, are discussed in Section 5.4.7.2.6.

5.4.7.2.8 Leakage Detection Capability for RHR System Leakage

The major portion of the RHRS is contained in the Safeguards Building between elevations 773'-0" and 810'-6". All leakages originating at RHR components will be collected by the floor drain system.

The effects of the leaks will be detected in the Control Room via the floor drain system alarms and area radiation monitoring alarms. Large leaks in the RHRS will be detected by interpretation of RHR flow parameters, area radiation monitoring alarms and high level alarms of floor drain sumps nos. 1 and 3. Small leaks will be alarmed in the Control Room by the area radiation monitors in the Safeguards Building. (See the listing for these monitors in Table 12.3-8.)

By interpretation of process parameters and alarms, the operators will determine the area where the leakage has occurred. Further information will be obtained by visual observation. System design permits complete isolation of the faulted RHR loop with no impact on plant safety.

Depending on the severity of the leak, the operator will make a determination on the proper course of action. After a loop is taken out of service, it can be drained and vented, and prepared for maintenance.

The occurrence of leaks will be alarmed in the Control Room. The Safeguards sumps alarms and area radiation monitoring alarms are not designed in accordance with the requirements of IEEE-279; however, the area radiation monitoring system is designed in accordance with the test and calibration requirements of IEEE-279.

5.4.7.3 Performance Evaluation

The performance of the RHRS in reducing reactor coolant temperature is evaluated through the use of heat balance calculations on the RCS, and the Component Cooling Water System at stepwise intervals following the initiation of residual heat removal operation. Heat removal through the residual heat removal and component cooling water heat exchangers is calculated at each interval by use of standard water-to-water heat exchanger performance correlations; the resultant fluid temperatures for the residual heat removal and component cooling water systems are calculated and used as input to the next interval's heat balance calculation.

Assumptions utilized in the series of heat balance calculations describing plant residual heat removal cooldown are as follows:

1. Residual heat removal operation is initiated after reactor shutdown as follows:

Normal Plant Cooldown	4 hours
BTP RSB 5-1 Cooldown	9 hours
Fire Safe Shutdown	14 hours
Cooldown in the event of a DBA in the opposite unit	4 hours
Cooldown in accordance with technical specifications	12 hours

2. Residual heat removal operation begins at a reactor coolant temperature of 350°F.

3. Thermal equilibrium is maintained throughout the RCS during the cooldown.

4. Component cooling water temperature during cooldown is limited to a maximum of 122°F.

5. The effect of common (shared) auxiliary heat loads on the CCWS operation are assumed as follows:

Normal Plant Cooldown	The opposite unit can assume the common auxiliary heat loads.
BTP RSB 5-1 Cooldown	The opposite unit can assume the common auxiliary heat loads.
Fire Safe Shutdown	Each unit must be capable of shutting down without system support of the other.
Cooldown in the event of a DBA in the opposite unit	The cooldown unit can assume common auxiliary loads.
Cooldown in accordance with technical specifications	The opposite unit can assume the common auxiliary heat loads.

Cooldown curves calculated using this method are provided for the case of all residual heat removal components operable (Figure 5.4-8) and for the case of a single train residual heat removal cooldown (Figure 5.4-9).

5.4.7.4 Preoperational Testing

Preoperational testing of the RHRS is addressed in Chapter 14.

5.4.8 REACTOR WATER CLEANUP

This section is not applicable to the CPNPP.

5.4.9 MAIN STEAM LINE AND FEEDWATER PIPING

The main steam line is described in Section 10.3 and the feedwater piping is described in Section 10.4.7.

5.4.10 PRESSURIZER

5.4.10.1 Design Bases

The general configuration of the pressurizer is shown in Figure 5.4-10. The design data of the pressurizer are given in Table 5.4-9. Codes and material requirements are provided in Section 5.2.

The pressurizer provides a point in the RCS where liquid and vapor can be maintained in equilibrium under saturated conditions for pressure and control purposes.

5.4.10.1.1 Pressurizer Surge Line

The surge line is sized to limit the pressure drop between the RCS and the safety valves with maximum allowable discharge flow from the safety valves. Overpressure of the RCS does not exceed 110 percent of the design pressure.

The surge line and the thermal sleeves at each end are designed to withstand the thermal stresses resulting from volume surges of relatively hotter or colder water which may occur during operation.

The pressurizer surge line nozzle diameter is given in Table 5.4-9 and the pressurizer surge line dimensions are shown in Figure 5.1-1, Sheet 2.

5.4.10.1.2 Pressurizer

The volume of the pressurizer is equal to, or greater than, the minimum volume of steam, water, or total of the two which satisfies all of the following requirements:

1. The combined saturated water volume and steam expansion volume is sufficient to provide the desired pressure response to system volume changes.

2. The water volume is sufficient to prevent the heaters from being uncovered during a step load increase of 10 percent at full power.

3. The steam volume is large enough to accommodate the surge resulting from 50 percent reduction of full load with automatic reactor control and 40 percent steam dump without the water level reaching the high level reactor trip point.

4. The steam volume is large enough to prevent water relief through the safety valves following a loss of load with the high water level initiating a reactor trip, without reactor control or steam dump.

5. The pressurizer will not empty following reactor trip and turbine trip.

6. The emergency core cooling signal is not activated during reactor trip and turbine trip.

5.4.10.2 Design Description

5.4.10.2.1 Pressurizer Surge Line

The pressurizer surge line connects the pressurizer to one reactor hot leg. The line enables continuous coolant volume pressure adjustments between the RCS and the pressurizer.

5.4.10.2.2 Pressurizer

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads constructed of carbon steel, with austenitic stainless steel cladding on all surfaces exposed to the reactor coolant. A stainless steel liner or tube may be used in lieu of cladding in some nozzles.

The surge line nozzle and removable electric heaters are installed in the bottom head. The heaters are removable for maintenance or replacement. A thermal sleeve is provided to minimize stresses in the surge line nozzle. A screen at the surge line nozzle and baffles in the lower section of the pressurizer prevent an insurge of cold water from flowing directly to the steam/water interface and assist mixing.

Spray line nozzle, relief and safety valve connections are located in the tip head of the vessel. Spray flow is modulated by automatically controlled air operated valves. The spray valves also can be operated manually by a switch in the Control Room.

A small, continuous spray flow is provided through a manual bypass valve around the power operated spray valves to assure that the pressurizer liquid is homogeneous with the coolant and to prevent excessive cooling of the spray piping.

During an outsurge from the pressurizer, flashing of water to steam and generating of steam by automatic actuation of the heaters keep the pressure above the minimum allowable limit. During an insurge from the RCS, the spray system, which is fed from two cold legs, condenses steam in the vessel to prevent the pressurizer pressure from reaching the setpoint of the power operated relief valves for normal design transients. Heaters are energized on high water level during insurge to heat the subcooled surge water that enters the pressurizer from the reactor coolant loop.

Material specifications are provided in Table 5.2-2 for the pressurizer, pressurizer relief tank, and the surge line. Design transients for the components of the RCS are discussed in Section 3.9(N).1. Additional details on the pressurizer design cycle analysis are given in Section 5.4.10.3.5.

Pressurizer Instrumentation

Refer to Chapter 7 for details of the instrumentation associated with pressurizer pressure, level, and temperature.

Spray Line Temperatures

Temperatures in the spray lines from two loops are measured and indicated. Alarms from these signals are actuated by low spray water temperature. Alarm conditions indicate insufficient flow in the spray lines.

Safety and Relief Valve Discharge Temperatures

Temperatures in the pressurizer safety and relief valve discharge lines are measured and indicated. An increase in a discharge line temperature is an indication of leakage or relief through the associated valve.

5.4.10.3 Design Evaluation

5.4.10.3.1 System Pressure

Whenever a steam bubble is present within the pressurizer, RCS pressure is maintained by the pressurizer. Analyses indicate that proper control of pressure is maintained for the operating conditions.

A safety limit has been set to ensure that the RCS pressure does not exceed the maximum transient value allowed under the ASME Code, Section III, and thereby assures continued integrity of the RCS components.

Evaluation of plant conditions of operation which follow indicate that this safety limit is not reached.

During startup and shutdown, the rate of temperature change is controlled by the operator. The maximum heatup/cooldown rate of the pressurizer is governed by the Technical Specifications. Heatup rate is controlled by pump energy and by the pressurizer electrical heating capacity. This heatup rate takes into account the continuous spray flow provided to the pressurizer. When the reactor core is shutdown, the heaters are de-energized.

When the pressurizer is filled with water, i.e., during initial system heatup, and near the end of the second phase of plant cooldown, RCS pressure is maintained by the letdown flow rate via the RHRS.

5.4.10.3.2 Pressurizer Performance

The pressurizer has a minimum free internal volume. The normal operating water volume at full load conditions is a percentage of the free internal vessel volume. Under part load conditions, the water volume in the vessel is reduced for proportional reductions in plant load. The various plant operating transients are analyzed and the design pressure is not exceeded with the pressurizer design parameters as given in Table 5.4-9.

5.4.10.3.3 Pressure Setpoints

The RCS design and operating pressure together with the safety, power relief and pressurizer spray valves setpoints, and the protection system setpoint pressures are listed in Table 5.4-10. The design pressure allows for operating transient pressure changes. The selected design

margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics.

The pressurizer power-operated relief valve (PORV) setpoint value listed on Table 5.4-10 is that of the PORV automatic opening at power (2/2) logic function. When the pressurizer pressure goes above this value, the PORV will automatically open. The purpose of this logic function is to limit Reactor Coolant System (RCS) pressure when the reactor is at power or at hot standby and to prevent actuation of the pressurizer high pressure Reactor Trip when at power on certain operational transients, such as a load reduction. This 2/2 logic function has two inputs; the first input is from a control channel whose setpoint is effectively 2335 psig, which is the value listed on Table 5.4-10; the second input is an interlock which is derived from an independent pressurizer pressure channel and has a setpoint of 2185 psig such that when the pressurizer pressure is above this value the PORV automatic opening control is armed but will not cause the PORV to open as long as pressurizer pressure is below the setpoint of the control channel. The purpose of the interlock (i.e., the input set at 2185 psig) is to prevent depressurization of the RCS by automatically closing the PORV in the event the control input fails high.

5.4.10.3.4 Pressurizer Spray

Two separate, automatically controlled spray valves with remote manual overrides are used to initiate pressurizer spray. In parallel with each spray valve is a manual throttle valve which permits a small continuous flow through both spray lines to reduce thermal stresses and thermal shock when the spray valves open, and to help maintain uniform water chemistry and temperature in the pressurizer. Temperature sensors with low alarms are provided in each spray line to alert the operator to insufficient bypass flow. The layout of the common spray line piping to the pressurizer forms a water seal which prevents the steam buildup back to the control valves.

The spray rate is selected to prevent the pressurizer pressure from reaching the operating setpoint of the power relief valves during a step reduction in power level of 10 percent of full load.

The pressurizer spray lines and valves are large enough to provide adequate spray using as the driving force the differential pressure between the surge line connection in the hot leg and the spray line connection in the cold leg. The spray line inlet connections extend into the cold leg piping in the form of a scoop so that the velocity head of the reactor coolant loop flow adds to the spray driving force. The spray valves and spray line connections are arranged so that the spray will operate when one reactor coolant pump is not operating. The line may also be used to assist in equalizing the boron concentration between the reactor coolant loops and the pressurizer.

A flow path from the Chemical and Volume Control System to the pressurizer spray line is also provided. This additional facility provides auxiliary spray to the vapor space of the pressurizer during cooldown if the reactor coolant pumps are not operating. The thermal sleeves on the pressurizer connection and the spray piping are designed to withstand the thermal stresses resulting from the introduction of cold spray water.

5.4.10.3.5 Pressurizer Design Analysis

The occurrences for pressurizer design cycle analysis are defined as follows:

1. The temperature in the pressurizer vessel is always, for design purposes, assumed to equal saturation temperature for the existing RCS pressure increase. In this case the temperature of the steam space will exceed the saturation temperature since an isentropic compression of the steam is assumed.

   The only exception of the above occurs when the pressurizer is filled solid during plant startup and cooldown.

2. The temperature shock on the spray nozzle is assumed to equal the temperature of the nozzle minus the cold leg temperature and the temperature shock on the surge nozzle is assumed to equal the pressurizer water space temperature minus the hot leg temperature.

3. Pressurizer spray is assumed to be initiated instantaneously to its design value as soon as the RCS pressure increases 40 psi above the nominal operating pressure. Spray is assumed to be terminated as soon as the RCS pressure falls 40 psi below normal operating pressure.

4. Unless otherwise noted, pressurizer spray is assumed to be initiated once per occurrence of each transient condition. The pressurizer surge nozzle is also assumed to be subject to one temperature transient per transient condition, unless otherwise noted.

5. At the end of each transient, except the faulted conditions, the RCS is assumed to return to a load condition consistent with the plant heatup transient.

6. Temperature changes occurring as a result of pressurizer spray are assumed to be instantaneous. Temperature changes occurring on the surge nozzle are also assumed to be instantaneous.

7. Whenever spray is initiated in the pressurizer, the pressurizer water level is assumed to be at the no-load level.

5.4.10.4 Test and Inspections

The pressurizer is designed and constructed in accordance with the ASME Code, Section III.

To implement the requirements of the ASME Code, Section XI, the following welds are designed and constructed to present a smooth transition surface between the parent metal and the weld metal.

The path is ground smooth for ultrasonic inspection.

1. Support skirt to the pressurizer lower head.

2. Surge nozzle to the lower head.

3. Nozzles to the safety, relief, and spray lines.

4. Nozzle to safe end attachment welds.

5. All girth and longitudinal full penetration welds.

6. Manway attachment welds.

The liner within the safe end nozzle region extends beyond the weld region to maintain a uniform geometry for ultrasonic inspection.

Peripheral support rings are furnished for the removable insulation modules.

The pressurizer quality assurance program is given in Table 5.4-11.

5.4.11 PRESSURIZER RELIEF DISCHARGE SYSTEM

The Pressurizer Relief Discharge System collects, cools and directs for processing the steam and water discharged from the various safety and relief valves in the Containment. The system consists of the pressurizer relief tank, the safety and relief valve discharge piping, the relief tank spray header and associated piping, and the tank nitrogen supply, the vent to Containment and the drain to the Waste Processing System.

5.4.11.1 Design Bases

Codes and materials of the pressurizer relief tank and associated piping are given in Section 5.2. Design data for the tank are given in Table 5.4-12.

The system design is based on the requirement to absorb a discharge of steam equivalent to 110 percent of the full power pressurizer steam volume. The steam volume requirement is approximately that which would be experienced if the plant were to suffer a complete loss of load accompanied by a turbine trip but without the resulting reactor trip.

The minimum volume of water in the pressurizer relief tank is determined by the energy content of the steam to be condensed and cooled, by the assumed initial temperature of the water, and by the desired final temperature of the water volume. The initial water temperature is assumed to be 120°F, which corresponds to the design maximum expected Containment temperature for normal conditions. Provisions is made to permit cooling the tank should the water temperature rise above 120°F, which allows the contents of the tank to be drained directly to the Waste Processing System without cooling.

The vessel saddle supports and anchor bolt arrangement are designed to withstand the loadings resulting from a combination of nozzle loadings acting simultaneously with the vessel seismic and static loadings.

5.4.11.2 System Description

The piping and instrumentation diagram for the Pressurizer Relief Discharge System is given in Figure 5.1-1, Sheet 2.

The steam and water discharged from the various safety and relief valves inside the Containment is routed to the pressurizer relief tank if the discharged fluid is of reactor grade quality. Table 5.4-13 provides an itemized list of valves discharging to the tank together with references of the corresponding piping and instrumentation diagrams.

The tank normally contains water and a predominantly nitrogen atmosphere. In order to obtain effective condensing and cooling of the discharged steam, the tank is installed horizontally and the steam is discharged through a sparger pipe located near the bottom, under the water level. The sparger holes are designed to insure a resultant steam velocity close to sonic.

The tank is also equipped with an internal spray and a drain which are used to cool the water following a discharge. Cold water is drawn from the Reactor Makeup Water System, or the content of the tank is circulated through the reactor coolant drain tank heat exchanger of the Waste Processing System and back into the spray header.

The nitrogen gas blanket is used to control the atmosphere in the tank and to allow room for the expansion of the original water plus the condensed steam discharge. The tank gas volume is calculated using a final pressure based on an arbitrary design pressure of 100 psig. The design discharges raises the worst case initial conditions to 50 psig, a pressure low enough to prevent fatigue of the rupture discs. Provisions are made to permit the gas in the tank to be periodically analyzed to monitor the concentration of hydrogen and/or oxygen.

The contents of the vessel can be drained to the waste holdup tank in the Waste Processing System or the recycle holdup tank in the Boron Recycle System via the reactor coolant drain tank pumps in the Waste Processing System.

5.4.11.2.1 Pressurizer Relief Tank

The general configuration of the pressurizer relief tank is shown in Figure 5.4-11. The tank is a horizontal, cylindrical vessel with elliptical dished heads. The vessel is constructed of austenitic stainless steel and is overpressure protected in accordance with ASME Code, Section VIII, Division 1, by means of two safety heads with stainless steel rupture discs.

A flanged nozzle is provided on the tank for the pressurizer discharge line connection to the sparger pipe. The tank is also equipped with an internal spray connected to a cold water inlet and with a bottom drain, which are used to cool the tank following a discharge.

5.4.11.3 Safety Evaluation

The Pressurizer Relief Discharge System does not constitute part of the reactor coolant pressure boundary per 10CFR50, Section 50.2, since all of its components are downstream of the RCS safety and relief valves. Thus, General Design Criteria 14 and 15 are not applicable.

Furthermore, complete failure of the auxiliary systems serving the pressurizer relief tank will not impair the capability for safe plant shutdown.

The design of the system piping layout and piping restraints is consistent with Regulatory Guide 1.46. Westinghouse requires the architect engineer to meet Regulatory Guide 1.46 by restraining the safety and relief valve discharge piping so that integrity and operability of the valves are maintained in the event of a rupture.

Regulatory Guide 1.67 is not applicable since the system is not an open discharge system.

The Pressurizer Relief Discharge System is capable of handling the design discharge of steam without exceeding the design pressure and temperature.

The volume of water in the pressurizer relief tank is capable of absorbing the heat from the assumed discharge maintaining the water temperature below 200°F. If a discharge exceeding the design basis should occur, the relief device on the tank would pass the discharge through the tank to the Containment.

The rupture discs on the relief tank have a relief capacity equal to or greater than the combined capacity of the pressurizer safety valves. The tank design pressure is twice the calculated pressure resulting from the design basis safety valve discharge described in Section 5.4.11.1. The tank and rupture discs holders are also designed for full vacuum to prevent tank collapse if the content cools following a discharge without nitrogen being added.

Westinghouse, using piping layouts and conservative assumptions as to conditions in the pressurizer relief tank, calculated the backpressure at the safety valves. These calculations confirmed that the discharge piping from the safety and relief valves to the relief tank is sufficiently large to prevent backpressure at the safety valves from exceeding 20 percent of the setpoint pressure at full flow.

The overpressure transient analysis, requiring Safety Valve actuation, assumes the valves operate at their design maximum relieving capacity (see Table 5.4-16). The backpressure (see Table 5.4-16) is consistent with the valves' balanced bellows operating capability and is low enough not to affect the valve relieving capacity.

5.4.11.4 Instrumentation Requirements

The pressurizer relief tank pressure transmitter provides an indication of pressure relief tank pressure. An alarm is provided to indicate high tank pressure.

The pressurizer relief tank level transmitter supplies a signal for an indicator with high and low level alarms. The high level alarm setpoint for the pressurizer relief tank (PRT) will be less than the maximum PRT level that would prevent the PRT from exceeding 50 psig (stated in Section 5.4.11.2) during the design safety valve discharge to the PRT.

The temperature of the water in the pressurizer relief tank is indicated, and an alarm actuated by high temperature informs the operator that cooling of the tank contents is required.

5.4.11.5 Inspection and Testing Requirements

The system components are subject to nondestructive and hydrostatical testing during construction in accordance with Section VIII, Division 1 of the ASME Code.

During plant operation, periodic visual inspections and preventive maintenance are conducted on the system components according to normal industrial practice.

5.4.12 VALVES

5.4.12.1 Design Bases

As noted in Section 5.2, all valves out to and including the second valve normally closed or capable of automatic or remote closure, larger than 3/4 inch, are ANS Safety Class 1, and ASME III, Code Class 1 valves. All 3/4 inch or smaller valves in lines connected to the RCS are

Class 2 since the interface with the Class 1 piping is provided with suitable orificing for such valves. Design data for the RCS valves are given in Table 5.4-14.

For a check valve to qualify as part of the RCS it must be located inside the containment system. When the second of two normally open check valves is considered part of the RCS (as defined in Section 5.1), means are provided to periodically assess back-flow leakage of the first valve when closed.

To ensure that the valves will meet the design objectives, the materials of construction minimize corrosion/erosion and ensure compatibility with the environment, leakage is minimized to the extent practicable by design, and Class 1 stresses are maintained within the limits of the ASME Code, Section III.

5.4.12.2 Design Description

All manual and motor operated valves of the RCS which are 3 inches and larger are provided with double packed stuffing boxes and intermediate latern ring leakoff connections. All throttling control valves, regardless of size, provided with double packed stuffing boxes and with stem leakoff connections. In general, RCS leakoff connections are piped to a closed collection system. Leakage to the atmosphere is essentially zero for these valves.

Gate valves at the engineered safety features interface are wedge design and are essentially straight through. The wedges are flex- wedge or solid. All gate valves have backseats. Globe valves are “T” and “Y” style. Check valves are swing type for sizes 2-1/2 inches and larger. All check valves which contain radioactive fluid are stainless steel and do not have body penetrations other than the inlet, outlet and bonnet. The check hinge is serviced through the bonnet.

The accumulatory check valve is designed such that at the required flow, the resulting pressure drop is within the specified limits. All operating parts are contained within the body. The disc has limited rotation to provide a change of seating surface and alignment after each valve opening.

5.4.12.3 Design Evaluation

The design/analysis requirements for Class 1 valves, as discussed in Section 5.2, limit stresses to levels which ensure the structural integrity of the valves. In addition, the testing program described in Section 3.9N demonstrate the ability of the valves of operate as required during anticipated and postulated plant conditions.

Reactor coolant chemistry parameters are specified in the design specifications to assure the compatibility of valve construction materials with the reactor coolant. To ensure that the reactor coolant continues to meet these parameters, the chemical composition of the coolant will be analyzed periodically.

The above requirements and procedures, coupled with the previously described design features for minimizing leakage, ensure that the valves will perform their intended functions as required during plant operation.

5.4.12.4 Tests and Inspections

All RCS valves are tested in accordance with the requirements of the ASME Code, Section III. The tests and inspections discussed in Section 3.9N are performed to ensure the operability of active valves. In place operational testing is performed on valves, as defined in the ASME OM Code.

There are no full penetration welds within valve body walls. Valves are accessible for disassembly and internal visual inspection to the extent practical. Plant layout configurations determine the degree of inspectability. The valve quality assurance program is given in Table 5.4-15. Inservice inspection is discussed in Section 5.2.4.

5.4.13 SAFETY AND RELIEF VALVES

5.4.13.1 Design Bases

The combined capacity of the pressurizer safety valves is designed to accommodate the maximum surge resulting from complete loss of load.

This objective is met without reactor trip or any operator action by the opening of the steam safety valves when steam pressure reaches the steam side safety setting.

The pressurizer power operated relief valves are designed to limit pressurizer pressure to a value below the fixed high pressure reactor trip setpoint. They are designed to fail to the closed position on a loss of nitrogen supply. The valves are classified as active. Each of the two PORVs is supplied with an independent, seismically designed supply of nitrogen. See Section 5.2.2.11.1.

5.4.13.2 Design Description

The pressurizer safety valves are of the pop type. The valves are spring loaded, open by direct fluid pressure action, and backpressure compensation features.

The pipe connecting the pressurizer nozzles to their respective safety valves are shaped in the form of a loop seal. Condensate resulting from normal heat losses accumulates in the loop. The water prevents any leakage of hydrogen gas or steam through the safety valve seats. If the pressurizer pressure exceeds the set pressure of the safety valves, they start lifting, and the water from the seal discharges during the accumulation period.

The pressurizer power operated relief valves are pneumatic actuated valves which respond to a signal from a pressure sensing system or to manual control. Remotely operated block valves provided to isolate the power operated relief valves if excessive leakage develops.

Temperatures in the pressurizer safety and relief valve discharge lines are measured and indicated. An increase in a discharge line temperature is an indication of leakage or relief through the associated valve. Design parameters for the pressurizer spray control, safety, and power relief valves are given in Table 5.4-16.

5.4.13.3 Design Evaluation

The pressurizer safety valves prevent RCS pressure from exceeding 110 percent of system design pressure, in compliance with the ASME Code.

The Maximum design basis water relief rate through the three safety valves is a total of approximately 17.4 ft^3/sec. The loop seal discharge transient is bounding for all other discharge transient cases including feedwater line break.

The pressurizer safety valves have been analyzed for the FWLB conditions consistent with the work performed for WCAP-11677. The conclusions in WCAP-11677 that the Crosby 6M6 valves can pass slightly subcooled water at least three times without damage applies.

The pressurizer power relief valves prevent actuation of the fixed reactor high pressure trip for all design transients up to and including the design step load decreases with steam dump. The relief valves also limit undesirable opening of the spring loaded safety valves. Note that setpoint studies to date indicate that the pressure rise in a four-loop plant for the design step load decrease of 10 percent from full power is limited to 60 psi. These studies also indicate that the design step load decrease of 10 percent under N-1 loop operation is limited to approximately 50 psi. In both cases, the pressure rise is not sufficient to actuate the power operated relief valves, and thus this design is conservative.

5.4.13.4 Tests and Inspections

All safety and relief valves are subjected to hydrostatic tests, seat leakage tests, operational tests, and inspections as required. For safety valves that are required to function during a faulted condition, additional tests are performed. These tests are described in Section 3.9N. Also, see Section II.D.1 for the RCS relief and safety valve testing program for valve operability under expected flow conditions for design basis transients and accidents.

There are no full penetration welds within the valve body walls. Valves are accessible for disassembly and internal visual inspection.

5.4.14 COMPONENT SUPPORTS

5.4.14.1 Design Bases

Component supports allow virtually unrestrained lateral thermal movement of the loop during plant operation and provide restraint to the loops and components during accident conditions. The loading combinations and design stress limits are discussed in Sections 3.9N.1.1 and 3.9N.1.4.7. Material properties are discussed in Section 5.2.3. Support design is in accordance with the ASME Code, Section III, Subsection NF. The design maintains the integrity of the RCS boundary for normal and accident conditions and satisfies the requirements of the piping code. Results of piping and supports stress evaluation are presented in Section 3.9N.

5.4.14.2 Description

The support structures are welded structural steel sections. Linear type structures (tension and compression struts, columns, and beams) are used in all cases except for the reactor vessel

supports, which are plate type structures. Attachments to the supported equipment are nonintegral type that are bolted to or bear against the components. The supports-to-concrete attachments are either embedded anchor bolts or fabricated assemblies.

The supports permit virtually unrestrained thermal growth of the supported systems but restrain vertical, lateral, and rotational movement resulting from seismic and pipe break loadings. This is accomplished using spherical bushings in the columns for vertical support and girders, bumper pedestals, hydraulic snubbers, and tie-rods for lateral support.

Because of manufacturing and construction tolerances, ample adjustment in the support structures must be provided to ensure proper erection alignment and fit-up. This is accomplished by shimming or grouting at the supports-to-concrete interface and by shimming at the supports-to-equipment interface.

The supports for the various components are described in the following paragraphs.

5.4.14.2.1 Reactor Pressure Vessel

Supports for the reactor vessel (Figures 5.4-12, 12A and 12B) are individual, air-cooled rectangular box structures beneath the vessel nozzles bolted to the primary shield wall concrete. Each box structure consists of a horizontal top plate that receives loads from the reactor vessel shoe, a horizontal bottom plate supported by short columns which transfer the loads to the primary shield wall concrete, and connecting vertical plates. The supports are air cooled to maintain the supporting concrete temperature within acceptable levels.

5.4.14.2.2 Steam Generator

As shown in Figure 5.4-13, the steam generator supports will consist of the following elements:

1. Vertical support

   Four individual columns will provide vertical support for each steam generator. These will be bolted at the top to the steam generator and at the bottom to the concrete structure.

   Spherical ball bushing at the top and bottom of each column will allow unrestrained lateral movement of the steam generator during heatup and cooldown. The column base design permits both horizontal and vertical adjustment of the steam generator for erection and adjustment of the system.

2. Lower lateral support

   Lateral support is provided at the generator tubesheet by fabricated steel girders and struts. These are bolted to the compartment walls and include bumpers that bear against the steam generator but permit unrestrained movement of the steam generator during changes in system temperature. Stresses in the beam caused by wall displacements during compartment pressurization are considered in the design.

3. Upper lateral support

The upper lateral support of the steam generator is provided by a built up ring plate girder at the operating deck. Hydraulic snubbers are used in RCS component supports on the steam generator upper lateral support for Unit 2, and are intended for shock arrest only. Thus, the two-way acting snubbers restrain sudden seismic or blowdown induced motion, but permit the normal thermal movement of the steam generator. Movement perpendicular to the thermal growth direction of the steam generator is prevented by struts. The exact configuration of the upper support and location of snubbers varies depending on the details of the supporting concrete. The snubbers have been eliminated for Unit 1.

The design specification for snubbers establishes the design, performance, fabrication, inspection, testing, packaging, shipping and installation requirements for the hydraulic shock struts (snubbers) to be used in conjunction with the RCS component supports. It is the intent of the specification to provide ASME Class I nuclear quality equipment and be in compliance with ASME B&PV Code Section III, including Subsection NF. The snubbers are built to the intent of ASME Code but are not stamped.

5.4.14.2.3 Reactor Coolant Pump

Three individual columns, similar to those used for the steam generator, provide the vertical support for each pump. Lateral support for seismic and blowdown loading is provided by three lateral tension tie bars. The pump supports are shown in Figure 5.4-14.

5.4.14.2.4 Pressurizer

The supports for the pressurizer, as shown in Figure 5.4-15, consist of:

1. A steel ring plate between the pressurizer skirt and the supporting concrete slab. The ring serves as a leveling and adjusting member for the pressurizer and may also be used as a template for positioning the concrete anchor bolts.

2. The upper lateral support consists of struts cantilevered off the compartment walls that bear against the “seismic lugs” provided on the pressurizer. The configuration of the lateral struts depends on the location of the concrete walls and piping within the compartment, as well as the orientation of the pressurizer.

5.4.14.2.5 Pipe Restraints

The application of leak-before-break technology to the CPNPP main loop piping has resulted in the exclusion of the main loop piping breaks from the design basis for dynamic effects (Sections 3.1.1.4 and 3.6B). The reactor coolant loop piping is qualified for LOCA dynamic effects from the loop branch nozzle breaks (breaks 12 and 13, Table 3.6B-2) without the main loop piping restraints (Figures 3.6B-89 to 92). These piping restraints are therefore not required for CPNPP Units 1 and 2. The crossover leg vertical run restraints, crossover leg restraints, and hot leg restraints have been functionally removed from the design by removal of saddle blocks and shims. Although not functionally required, the lateral restraints, illustrated in Figure 5.4-19 and the non-crushable insulation, illustrated in Figure 3.6B-89, are to remain as installed.

5.4.14.3 Evaluation

Detailed evaluation ensures the design adequacy and structural integrity of the reactor coolant loop and the primary equipment supports system. This detailed evaluation is made by comparing the analytical results with established criteria for acceptability. Structural analyses are performed to demonstrate design adequacy for safety and reliability of the plant in case of a large or small seismic disturbance and/or LOCA conditions. Loads which the system is expected to encounter often during its lifetime (thermal, weight, pressure) are applied and stresses are compared to allowable values as described in Section 3.9N.1.4.7.

The Safe Shutdown Earthquake and design basis LOCA resulting in a rapid depressurization of the system are required design conditions for public health and safety. The methods used for the analysis of the Safe Shutdown Earthquake and LOCA conditions are given in Section 3.9N.1.

5.4.14.4 Tests and Inspections

Weld inspection and standards are specified in accordance with Section V of the ASME Code. Welder qualifications and welding procedures are specified in accordance with Section IX of the ASME Code.

Testing of hydraulic snubbers is in accordance with the Technical Requirements Manual (TRM) and the Inservice Inspection Program Plan.

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6. WCAP-11127 (Proprietary), WCAP-11128 (Non-Proprietary), "Shotpeening Licensing Report for Comanche Peak Unit 1", May 1986.

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9. Steam Generator Progress Report: Revision 15, EPRI, Palo Alto, CA: 2000, 1000805.

10. Pressurized Water Reactor Generic Tube Degradation Predictions: U.S. Recirculating Steam Generators with Alloy 600TT and Alloy 690TT Tubing, EPRI, Palo Alto, CA: 2003, 1003589.

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TABLE 5.4-1
REACTOR COOLANT PUMP DESIGN PARAMETERS

(Sheet 1 of 2)

Unit design pressure (psig)	2485
Unit design temperature (°F)	650[a]
Unit overall height (ft)	26.93
Seal water injection (gpm)	8
Seal water return (gpm)	3
Cooling water flow (gpm)	495
Maximum continuous cooling water inlet temperature (°F)	108
Pump	
Capacity (gpm)	99,000
Developed head (ft)	288
NPSH required (ft)	Figure 5.4-2
Suction temperature (°F)	557.8
Pump discharge nozzle, inside diameter (in)	27-1/2
Pump suction nozzle, inside diameter (in)	31
Speed (rpm)	1183
Water volume (ft^3)	78.6[b]
Weight, dry (lbs)	205,330
Motor	
Type	Drip proof, squirrel cage induction, water/air cooled
Power (hp)	7000
Voltage (volts)	6600
Phase	3
Frequency (hz)	60
Insulation class	Class B, thermalastic epoxy insulation

TABLE 5.4-1
REACTOR COOLANT PUMP DESIGN PARAMETERS

(Sheet 2 of 2)

Starting	
Current	3000 amp @ 6600 volts
Input, hot reactor coolant	~489 amp
Input, cold reactor coolant	~669 amp
Pump moment of inertia, maximum (1b/ft^2)	
Flywheel	70,000
Motor	22,500
Shaft	520
Impeller	1,980

a) Design temperature of pressure retaining parts of the pump assembly exposed to the reactor coolant and injection water on the high pressure side of the controlled leakage seal shall be that temperature determined for the parts for a primary loop temperature of 650°F.

b) Composed of reactor coolant in the casing and of injection and cooling water in the thermal barrier.

TABLE 5.4-2
REACTOR COOLANT PUMP QUALITY ASSURANCE PROGRAM

	RT[a]	UT[a]	PT[a]	MT[a]
Castings	yes		yes	
Forgings				
Main shaft		yes	yes	
Main studs		yes	yes	
Flywheel (rolled plate)		yes		
Weldments				
Circumferential	yes		yes	
Instrument connections			yes	

a) RT - Radiographic.
UT - Ultrasonic.
PT - Dye penetrant.
MT - Magnetic particle.

TABLE 5.4-3
STEAM GENERATOR DESIGN DATA

Design pressure, reactor coolant side (psig)	2485
Design pressure, steam side (psig)	1285
Design temperature, reactor coolant side (°F)	650
Design temperature, steam side (°F)	600
Total heat transfer surface area (ft^2)	76,000 (Unit 1) 48,300 (Unit 2)
Maximum moisture carryover (wt percent)	0.10 (Unit 1) 0.25 (Unit 2)
Overall height (ft-in)	67-9 (Unit 1) 67-8 (Unit 2)
Number of U-tubes	Unit 1 – 5532 Unit 2 – 4570
U-tube nominal diameter (in)	0.750
Tube wall nominal thickness (in)	0.043
Number of manways	4
Inside diameter of manways (in)	16
Number of inspection ports	
2.0" Diameter	4 (Unit 2)
2.5" Diameter	16 (Unit 1) 2 (Unit 2)
4.0” Diameter	4 (Unit 1)
6.0" Diameter	4 (Unit 1) 5 (Unit 2)
Design fouling factor	0.00005 (Unit 2)
Preheat section fouling factor	0.00010 (Unit 2)

TABLE 5.4-4A
STEAM GENERATOR QUALITY ASSURANCE PROGRAM (UNIT 1)

	RT[a]	UT[a]	PT[a]	MT[a]	ET[a]
Tubesheet					
Forging		yes		yes	
Cladding		yes[b]	yes		
Channel head					
Forging		yes		yes	
Cladding			yes		
Secondary shell and head					
Forging		yes			
Tubes		yes			yes
Nozzles (forgings)		yes		yes	
Weldments					
Shell, circumferential	yes			yes	
Cladding (channel head-tubesheet joint cladding restoration)			yes		
Steam and feedwater nozzle to shell	yes			yes	
Support brackets				yes	
Tube to tubesheet			yes		
Instrument connections (primary and secondary)				yes	
Temporary attachments after removal				yes	
After hydrostatic test (all welds – where accessible)				yes	
Primary nozzle safe ends (forgings)		yes	yes		

a) RT - Radiographic.
UT - Ultrasonic.
PT - Dye penetrant.
MT - Magnetic particle.
ET - Eddy current.

b) Flat surfaces only.

TABLE 5.4-4B
STEAM GENERATOR QUALITY ASSURANCE PROGRAM (UNIT 2)

	RT[a]	UT[a]	PT[a]	MT[a]	ET[a]
Tubesheet					
Forging		yes		yes	
Cladding		yes[b]	yes		
Channel head					
Casting	yes			yes	
Cladding			yes		
Secondary shell and head					
Plates		yes			
Tubes		yes			yes
Nozzles (forgings)		yes		yes	
Weldments					
Shell, longitudinal	yes			yes	
Shell, circumferential	yes			yes	
Cladding (channel head-tubesheet joint cladding restoration)			yes		
Steam and feedwater nozzle to shell	yes			yes	
Support brackets				yes	
Tube to tubesheet			yes		
Instrument connections (primary and secondary)				yes	
Temporary attachments after removal				yes	
After hydrostatic test (all welds and complete cast channel head – where accessible)				yes	
Nozzle safe ends (if forgings)	yes		yes		
Nozzle safe ends (if weld deposit)			yes		

a) RT - Radiographic.
UT - Ultrasonic.
PT - Dye penetrant.
MT - Magnetic particle.
ET - Eddy current.

b) Flat surfaces only.

TABLE 5.4-5
REACTOR COOLANT PIPING DESIGN PARAMETERS

Reactor inlet piping, inside diameter (in)	27-1/2
Reactor inlet piping, nominal wall thickness (in)	2.32
Reactor outlet piping, inside diameter (in)	29
Reactor outlet piping, nominal wall thickness (in)	2.45
Coolant pump suction piping, inside diameter (in)	31
Coolant pump suction piping, nominal wall thickness (in)	2.60
Pressurizer surge line piping, nominal pipe size (in)	14
Pressurizer surge line piping, nominal wall thickness (in)	1.406
Reactor coolant loop piping	
Design/operating pressure (psig)	2485/2235
Design temperature (°F)	650
Pressurizer surge line	
Design pressure (psig)	2485
Design temperature (°F)	680
Pressurizer safety valve inlet line	
Design pressure (psig)	2485
Design temperature (°F)	680
Pressurizer (power operated) relief valve inlet line	
Design pressure (psig)	2485
Design temperature (°F)	680
Pressurizer relief tank inlet line	
Design pressure (psig)	700
Design temperature (°F)	600

TABLE 5.4-6
REACTOR COOLANT PIPING QUALITY ASSURANCE PROGRAM

	RT[a]	UT[a]	PT[a]
Fittings and pipe (castings)	yes		yes
Fittings and pipe (forgings)		yes	yes
Weldments			
Circumferential	yes		yes
Nozzle to runpipe (except no RT for nozzles less than 6 inches)	yes		yes
Instrument connections			yes
Castings	yes		yes (after finishing)
Forgings		yes	yes (after finishing)

a) RT - Radiographic.
UT - Ultrasonic.
PT - Dye penetrant.

TABLE 5.4-7
DESIGN BASES FOR RESIDUAL HEAT REMOVAL SYSTEM OPERATION

Residual Heat Removal System startup	~4 hours after reactor shutdown
Reactor Coolant System initial pressure (psig)	~425
Reactor Coolant System initial temperature (°F)	~350
Component cooling water maximum temperature (°F)	122
Cooldown time (hours after initiation of Residual Heat Removal System operation)	28
Reactor Coolant System temperature at end of cooldown (°F)	140
Decay heat generation	ANS 5.1 – 1979

TABLE 5.4-8
RESIDUAL HEAT REMOVAL SYSTEM COMPONENT DATA

Residual Heat Removal Pump		
Number	2	
Design pressure (psig)	600	
Design temperature (°F)	400	
Design flow (gpm)	3800	
Design head (ft)	350	
NPSH required at 3800 gpm (ft)	18	
Power (hp)	450	
Residual Heat Exchanger		
Number	2	
Design heat removal capacity (Btu/hr)	39.1×10^6	
Estimated UA (Btu/hr-°F)	2.3×10^6	
	Tube side	Shell side
Design pressure (psig)	600	165
Design temperature (°F)	400	200
Design flow (lb/hr)	1.9×10^6	3.8×10^6
Inlet temperature (°F)	140	105
Outlet temperature (°F)	119.4	115.2
Material	Austenitic stainless steel	Carbon steel
Fluid	Reactor coolant	Component cooling water

TABLE 5.4-9
PRESSURIZER DESIGN DATA

Design pressure (psig)	2485
Design temperature (°F)	680
Surge line nozzle diameter (in)	14
Heatup rate of pressurizer using heaters only (°F/hr)	55
Internal volume (ft^3)	1800

TABLE 5.4-10
REACTOR COOLANT SYSTEM DESIGN PRESSURE SETTINGS

	Psig
Hydrostatic test pressure	3107
Design pressure	2485
Safety valves (begin to open)	2485
High pressure reactor trip	2385
High pressure alarm	2310
Power operated relief valves	2335(a)
Pressurizer spray valves (full open)	2310
Pressurizer spray valves (begin to open)	2260
Proportional heaters (begin to operate)	2250
Operating pressure	2235
Proportional heater (full operation)	2220
Backup heaters on	2210
Low pressure alarm	2210
Pressurizer power operated relief valve interlock	2185(b)
Low pressure reactor trip (typical, but variable)	1885

a) At 2335 psig, a pressure signal initiates actuation (opening) of these valves. Remote manual control is also provided.

b) Below 2185 psig, the PORV is automatically closed to prevent depressurization of the RCS in the event the control input to the PORV (2335 psig) fails high.

TABLE 5.4-11
PRESSURIZER QUALITY ASSURANCE PROGRAM

	RT[a]	UT[a]	PT[a]	MT[a]
Heads				
Plates		yes		
Cladding			yes	
Shell				
Plates		yes		
Cladding			yes	
Heaters				
Tubing[b]		yes	yes	
Centering of element	yes			
Nozzle (forgings)		yes	yes[c]	yes[c]
Weldments				
Shell, longitudinal	yes			yes
Shell, circumferential	yes			yes
Cladding			yes	
Nozzle safe end (if forging)	yes		yes	
Instrument connection			yes	
Support skirt, longitudinal seam	yes			yes
Support skirt to lower head		yes		yes
Temporary attachments (after removal)				yes
All external pressure boundary welds after shop hydrostatic test				yes

a) RT - Radiographic.
UT - Ultrasonic.
PT - Dye penetrant.
MT - Magnetic particle.

b) Or a UT and ET.

c) MT or PT.

TABLE 5.4-12
PRESSURIZER RELIEF TANK DESIGN DATA

Design pressure (psig)		100
Rupture disc release pressure (psig)	Nominal: Range:	91 86-100
Design temperature (°F)		340
Total rupture disc relief capacity at 100 psig (lb/hr)		1.6×10^6

TABLE 5.4-13
RELIEF VALVE DISCHARGE TO THE PRESSURIZER RELIEF TANK

Reactor Coolant System		
3	Pressurizer safety valves	Figure 5.1-1
2	Pressurizer power operated relief valves	Figure 5.1-1
Residual Heat Removal System		
2	Residual heat removal pump suction line from the Reactor Coolant System hot legs	Figure 5.4-6
Chemical and Volume Control System		
1	Seal water return line	Figure 9.3-10
1	Letdown line	Figure 9.3-10

TABLE 5.4-14
REACTOR COOLANT SYSTEM VALVE DESIGN PARAMETERS

Design/normal operating pressure (psig)	2485/2235
Preoperational plant hydrotest (psig)	3107
Design temperature (°F)	650

TABLE 5.4-15
REACTOR COOLANT SYSTEM VALVES QUALITY ASSURANCE PROGRAM

	RT[a]	UT[a]	PT[a]
Boundary Valves, Pressurizer Relief and Safety Valves			
Castings (larger than 4 inches)	yes		yes
(2 inches to 4 inches)	yes[b]		yes
Forgings (larger than 4 inches)	(c)	(c)	yes
(2 inches to 4 inches)			yes

a) RT - Radiographic.
UT - Ultrasonic.
PT - Dye penetrant.

b) Weld ends only.

c) Either RT or UT.

TABLE 5.4-16
PRESSURIZER VALVES DESIGN PARAMETER

Pressurizer Spray Control Valves	
Number	2
Design pressure (psig)	2485
Design temperature (°F)	650
Design flow for valves full open, each (gpm)	450
Pressurizer Safety Valves	
Number	3
Saturated steam relieving capacity, ASME rated flow (lb/hr)	420,000
Set pressure (psig)	2485
Design temperature (°F)	650
Transient condition (°F) Superheated steam	680
Backpressure	
Normal (psig)	3 to 5
Expected during discharge (psig)	500
Water relieving capacity at 2575 psig per valve (lb/sec)	178.4
Pressurizer Power Relief Valves	
Number	2
Design pressure (psig)	2485
Design temperature (°F)	650
Saturated steam relieving capacity at 2235 psig per valve (lb/hr)	210,000
Transient condition (°F) Superheated steam	680
Water relieving capacity at 2235 psig per valve (lb/sec)	97.2

TABLE 5.4-17
FAILURE MODE AND EFFECTS ANALYSIS - RESIDUAL HEAT REMOVAL SYSTEM ACTIVE COMPONENTS - PLANT COOLDOWN OPERATION

(Sheet 1 of 7)

	Component		Failure Mode		[a]Effect on System Operation		[b]Failure Detection Method		Remarks
1.	Motor operated gate valve 1-8702A (1-8701A analogous)	a.	Fails to open on demand (open manual mode CB switch selection)	a.	Failure blocks reactor coolant flow from hot leg of RC loop #1 through train “A” of RHRS. Fault reduces redundancy of RHR coolant trains provided. No effect on safety for system operation. Plant cooldown requirements will be met by reactor coolant flow from hot leg of RC loop #4 flowing through train “B” of RHRS, however, time required to reduce RCS temperature will be extended.	a.	Valve position indication (closed to open position change) at CB; RC loop hot leg pressure indication at CB; RHR train “A” discharge flow indication and low flow alarm at CB; and RHR pump discharge pressure indication at CB.	1.	Valve is electrically interlocked with the containment sump and RWST isolation valves 1-8811A and 1-8812A, with RHR to charging pump suction line isolation valve 1-8804A and with “prevent-open” pressure interlock of RC loop hot leg. The valve can not be opened remotely from the CB if one of the indicated isolation valves is open or if RC loop pressure exceeds 425 psig.
								2.	If both trains of RHRS are unavailable for plant cooldown due to multiple component failures, the auxiliary feedwater system and S.G. power operated relief valves can be used to perform the safety function of removing residual heat.

TABLE 5.4-17
FAILURE MODE AND EFFECTS ANALYSIS - RESIDUAL HEAT REMOVAL SYSTEM ACTIVE COMPONENTS - PLANT COOLDOWN OPERATION

(Sheet 2 of 7)

	Component		Failure Mode		[a]Effect on System Operation		[b]Failure Detection Method		Remarks
2.	Motor operated gate valve 1-8702B (1-8701B analogous)	a.	Same failure modes as those stated for item #1	a.	Failure blocks reactor coolant flow from hot leg of RC loop #4 through train “B” of RHRS. Fault reduces redundancy of RHR cooling trains provided. No effect on safety for system operation. Plant cooldown flow from hot leg of RC loop #1 flowing through train “A” of RHRS. However, time required to reduce RCS temperature will be extended.	a.	Valve position indication (Closed to open position change) at CB; RC loop hot leg pressure indication at CB; RHR train “B” discharge flow inidcation and low flow Alarm at CB; and RHR pump discharge pressure indication at CB.	1.	Valve is electrically interlocked with the containment sump and RWST isolation valves 1-8811B and 1-8812B with RHR to safety injection pump suction line isolation valve 1-8804B and with “prevent-open” pressure interlock of RC loop hot leg. The valve can not be opened remotely from the CB if one of the indicated isolation valves is open or if RC loop pressure exceeds 425 psig.
								2.	Same as for Item #1.
3.	Residual heat removal pump #1, RHR pump #2 analogous)	a.	Fails to deliver working fluid	a.	Failure results in loss of reactor coolant flow from hot leg of RC loop #1 through train “A” of RHRS. Fault reduces redundancy of RHR coolant trains provided. No effect on safety for system operation. Plant cooldown requirements will be met by reactor coolant flow from hot leg of RC loop #4 flowing through train “B” of RHRS, however, time required to reduce RCS temperature will be extended.	a.	Open pump switchgear circuit breaker indication at CB; circuit breaker close position monitor light for group monitoring of component at CB; common breaker trip alarm at CB; RC loop #1 hot leg pressure indication(PI-405) at CB; RHR train A discharge flow indication (FI-618) and low flow alarm at CB; and pump discharge pressure indication (PI-614)	1.	The RHRS shares components with the ECCS. Pumps are tested as part of the ECCS testing program(see Section 6.3.4). Pump failure may also be detected during ECCS testing.

TABLE 5.4-17
FAILURE MODE AND EFFECTS ANALYSIS - RESIDUAL HEAT REMOVAL SYSTEM ACTIVE COMPONENTS - PLANT COOLDOWN OPERATION

(Sheet 3 of 7)

	Component		Failure Mode		[a]Effect on System Operation		[b]Failure Detection Method		Remarks
4.	Motor operated globe valve 1-FCV-610 (1-FCV-611 analogous)	a.	Fails to open on demand (open manual mode CB switch selection)	a.	Failure blocks miniflow line to suction of RHR pump “A” during cooldown operation of checking boron concentration level of coolant in train “A” of RHRS. No effect on safety for system operation. Operator may establish miniflow for RHR pump “A” operation by opening of CVCS letdown control valve (1-HCV-128) and manual valve 1-8734A to allow flow to CVCS.	a.	Valve position indication (closed to open position change) at CB.	1.	Valve is automatically controlled to open when pump discharge is less than 500 gpm and close when the discharge exceeds 1000 gpm. The valve protects the pump from dead-heading during ECCS operation. CB switch set to “Auto” position for automatic control of valve positioning.
		b.	Fails to close on demand (“Auto” mode CB switch selection)	b.	Failure allows for a portion of RHR heat exchanger “A” discharge flow to be bypassed to suction of RHR pump “A”. RHRS train “A” is degraded for the regulation of coolant temperature by RHR heat exchanger “A”. No effect on safety for system operation. Cooldown of RCS within established specification cooldown rate may be accomplished through operator action of throttling flow control valve 1-HCV-606 and controlling cooldown with redundant RHRS Train “B”.	b.	Valve position indication (open to closed position change) and at CB. RHRS Train “A” discharge flow indication (FI-618) at CB.		

TABLE 5.4-17
FAILURE MODE AND EFFECTS ANALYSIS - RESIDUAL HEAT REMOVAL SYSTEM ACTIVE COMPONENTS - PLANT COOLDOWN OPERATION

(Sheet 4 of 7)

	Component		Failure Mode		[a]Effect on System Operation		[b]Failure Detection Method		Remarks
5.	Air Diaphragm operated butterfly valve 1-FCV-618 (1-FCV-619 analogous)	a.	Fails to open on demand ("Auto" mode CB switch selection)	a.	Failure prevents coolant discharged from RHR pump "A" from bypassing RHR heat exchanger "A" resulting in mixed mean temperature of coolant flow to RCS being low. RHRS train "A" is degraded for the regulation of controlling temperature of coolant. No effect on safety for system operation. Cooldown of RCS within established specification rate may be accomplished through operator action of throttling flow control valve 1-HCV-606 and controlling cooldown with redundant RHRS train "B"	a.	RHR pump discharge temperature and RHRS train "A" discharge to RCS cold leg temperature recording (TR-612) at CB; and RHRS train "A" discharge to RCS cold leg flow indication (FI-618) at CB.	1.	Valve is designed to fail"closed" and is electrically wired so that electrical solenoid of the air diaphragm operator is energized to open the valve. Valve is normally "closed" to align RHRS for ECCS the valve. Valve operation during plant power operation and load follow.
		a.	Fails to close on demand ("Auto" mode CB switch selection	b.	Failure allows coolant discharged from RHR pump "A" to bypass RHR heat exchanger "A" resulting in mixed mean temperature of coolant flow to RCS being high. RHRS train "A" is degraded for the regulation of controlling temperature of coolant. No effect on safety for system operation. Cooldown of RCS within established specification rate may be accomplished through operator action of throttling flow control valve 1-HCV-606 and controlling cooldown with redundant RHRS train "B", however, cooldown time will be extended.	b.	Same method of detection as those stated above.		

TABLE 5.4-17
FAILURE MODE AND EFFECTS ANALYSIS - RESIDUAL HEAT REMOVAL SYSTEM ACTIVE COMPONENTS - PLANT COOLDOWN OPERATION

(Sheet 5 of 7)

	Component		Failure Mode		[a]Effect on System Operation		[b]Failure Detection Method		Remarks
6.	Air diaphragm operated butterfly valve 1-HCV-606 (1-HCV-607 analogous)	a.	Fails to close on demand for flow reduction	a.	Failure prevents control of coolant discharge flow from RHR heat exchanger "A" resulting in loss of mixed mean temperature coolant flow adjustment to RCS. No effect on safety for system operation. Cooldown of RCS within established specification rate may be accomplished by operator action of controlling cooldown with redundant RHRS train "B".	a.	Same methods of detection as those stated for item #5. In addition, monitor light (valve not open) for group monitoring of components at CB.	1.	Valve is designed to fail "open", The valve is normally "open" to align RHRS for ECS operation during plant power operation and load follow.
		b.	Fails to open on demand for increased flow	b.	Same effect on system operation as that stated above for failure mode "Fails to close on demand for flow reduction."	b.	Same methods as those stated above for failure mode "Fails to close on demand for flow reduction.		
7.	Manual globe valve 1-8734A (1-8734B analogous)	a.	Fails closed	a.	Failure blocks flow from train "A" of RHRS to CVCS letdown heat exchanger. Fault prevents (during the initial phase of plant cooldown) the adjustment of boron concentration level of coolant in lines of RHRS train "A" so that it equals the concentration level in the RCS using the RHR cleanup line to CVCS. No effect on safety for system operation. Operator can balance boron concentration levels by cracking open flow control valve 1-HCV-606 to permit flow to cold leg of loop #1 of RCS in order to balance levels using normal CVCS letdown flow.	a.	CVCS letdown flow indication (FI-132) at CB.	1.	Valve is normally "closed" to align the RHRS for ECCS operation during plant power operation and load follow.

TABLE 5.4-17
FAILURE MODE AND EFFECTS ANALYSIS - RESIDUAL HEAT REMOVAL SYSTEM ACTIVE COMPONENTS - PLANT COOLDOWN OPERATION

(Sheet 6 of 7)

	Component		Failure Mode		[a]Effect on System Operation		[b]Failure Detection Method		Remarks
8.	Air diaphragm operated globe valve 1-HCV-128	a.	Fails to open on demand	a.	Failure blocks flow from train “A” and “B” of RHRS to CVCS letdown heat exchanger. Fault prevents use of of RHR cleanup line to CVCS for balancing boron concentration levels of RHR trains “A” and “B” with RCS during initial cooldown operation and later in plant cooldown for letdown flow. No effect on safety for system operation. Operator can balance boron concentration levels with similar actions, using pertinent flow control valve 1-HCV-606 and 1-HCV-607, as stated above for item #7. Normal CVCS letdown flow can be used for purification if RHRS cleanup line is not available.	a.	Valve position indication (degree of opening) at CB and CVCS letdown flow indication (FI-132) at CB.	1. 2.	Same remark as that stated above for item #7. Valve is the boundary between CVCS and RHRs. It provides a path for RCS letdown pressure control and purification during shutdown conditions.
9.	Motor operated gate valve 1-8812A (1-8812B analogous)	a.	Fails to close on demand	3.	Failure reduces the redundancy of isolation valves provided to flow isolate RHRS train “A” from RWST. No effect on safety for system operation. Check valve 1-8958A in series with MO-valve provides the primary isolation against the bypass of RCS coolant flow from the suction of RHR pump”A” to RWST.	a.	Valve position indication (open to closed position change) at CB and valve (closed) monitor light for group monitoring at CB.	1.	Valve is a component of the ECCS that performs an RHR function dduring plant cooldown. Valve is normally “open” to align the RHRS for ECCS operation during plant power operation and load

List of acronyms and abbreviations

Auto - Automatic

CB - Control Board

CVCS - Chemical and Volume Control System

TABLE 5.4-17
FAILURE MODE AND EFFECTS ANALYSIS - RESIDUAL HEAT REMOVAL SYSTEM ACTIVE COMPONENTS - PLANT COOLDOWN OPERATION

(Sheet 7 of 7)

Component	Failure Mode	[a]Effect on System Operation	[b]Failure Detection Method	Remarks

ECCS - Emergency Core Cooling System

MO - Motor Operated

RC - Reactor Coolant

RCS - Reactor Coolant System

RHR - Residual Heat Removal

RHRS - Residual Heat Removal System

RWST - Refueling Water Storage Tank

SG - Steam Generator

a) See list at end of table for definition of acronym and abbreviations used.

b) As part of plant operation, periodic tests, surveillance inspections and instrument calibrations are made to monitor equipment and performance. Failures may be detected during such monitoring of equipment in addition to detection methods noted.

TABLE 5.4-18
TABLE DELETED

TABLE 5.4-19
UNIT 1 RCP FLYWHEEL DATA

Motor Unit	Melt Number	Charpy V-Notch (ft-lbs)	Lateral Expansion (mils)	Test Temp (°F)	T_{NDT}[(a)] (°F)	RT_{NDT} (°F)	Yield Strength (psi)	Tensile Strength (psi)	Elongation (% in 2")
01	B9692-2	58, 61, 60 (T)	51, 49, 53, (T)	70	10	10	69,300	91,100	24 (T)
		118, 116, 116 (L)	79, 81, 80 (L)	70			76,500	97,500	22 (L)
	B0510-1	80, 78, 72 (T)	73, 71, 68 (T)	70	10	10	70,900	92,500	23 (T)
		178, 180, 180 (L)	97, 98, 96 (L)	70			75,100	94,500	23 (L)
02	B0510-4	81, 82, 79 (T)	74, 70, 72 (T)	70	10	10	72,200	93,500	26 (T)
		150, 154, 151 (L)	95, 92, 96 (L)	70			73,900	96,500	24 (L)
	B0510-1	See data above for Motor Unit 01.							
03	B9692-2	See data above for Motor Unit 01.							
	B0510-1	See data above for Motor Unit 01.							
04	B0510-1	See data above for Motor Unit 01.							
	B0510-4	See data above for Motor Unit 02.							

a) Based on two drop weight test exhibiting no breaks at 20°F

TABLE 5.4-19A
UNIT 2 RCP FLYWHEEL DATA

Motor Unit	Melt Number	Charpy V-Notch (ft-lbs)	Lateral Expansion (mils)	Test Temp (°F)	T_{NDT} (°F)	RT_{NDT}* (°F)	Yield Strength (psi)	Tensile Strength (psi)	Elongation (% in 2")
01	B2934-3	90, 82, 92 (T)	77, 70, 78, (T)	70	10	10	70,100	92,900	20 (T)
		136, 128, 130 (L)	86, 84, 88 (L)	70			63,000	87,000	22 (L)
	D6482-3	110, 108, 112 (T)	81, 76, 80 (T)	70	10	10	70,100	90,500	26 (T)
		120, 118, 116 (L)	80, 82, 78 (L)	70			67,500	90,000	24 (L)
02	B2685-1	96, 98, 92 (T)	77, 76, 72 (T)	70	10	10	81,800	97,500	23 (T)
		166, 170, 168 (L)	94, 96, 92 (L)	70			67,100	91,000	23 (L)
	A5246-3	110, 116, 108 (T)	90, 86, 89 (T)	70	10	10	65,700	89,600	29 (T)
		128, 130, 130 (L)	94, 93, 92 (L)	70			65,800	88,800	27 (L)
03	B2934-3	See data above for Motor Unit 01.							
	D6482-3	See data above for Motor Unit 01.							
04	D6482-3	See data above for Motor Unit 01.							
	A5246-3	See data above for Motor Unit 02.							

5A EVALUATION OF COMPLIANCE WITH NRC BRANCH TECHNICAL POSITION RSB 5-1 ON DESIGN REQUIREMENTS OF THE RESIDUAL HEAT REMOVAL SYSTEM

The following describes the manner by which CPNPP complies with the technical requirements of BTP RSB 5-1. Comanche Peak is a Class 2 plant (as defined by the implementation section of BTP RSB 5-1) and is, thus, subject to the technical requirements of RSB 5-1 only as they apply to Class 2 plants. Only partial compliance with the technical position is required where manual actions or repairs can be demonstrated to be an acceptable alternative to strict compliance. The safe shutdown design basis for Comanche Peak is hot standby. The functional requirements of BTP RSB 5-1, the CPNPP Cold Shutdown Scenario, a Single Failure Analysis, and a discussion on Natural Circulation are provided below.

I. FUNCTIONAL REQUIREMENTS OF BTP RSB 5-1

1. Provyide safety grade steam generator dump valves, operators, air and power supplies which meet the single failure criterion.

   One safety grade steam generator power-operated atmospheric relief valve (PORV) is provided for each of the four steam generators. The PORV control circuitry and the valve operator meets safety grade criteria (Class 1E). A permanent safety grade air supply bottle for each PORV has been added to the CPNPP design. These air reservoirs (safety class 3 and Seismic Category I) will provide motive power to the PORV's until local manual operator control is available in the event that the plant air supply is unavailable. See Section 9.3.1.2 for related information. See Section II.1 (Cold Shutdown Scenario - Residual Heat Removal) and Section III.1 (Single Failure Evaluation - Residual Heat Removal) as provided below.

2. Provide the capability to cooldown to cold shutdown in approximately 36 hours assuming the most limiting single failure and loss of offsite power or show that manual actions inside or outside containment or return to hot standby until the manual actions or maintenance can be performed to correct the failure provides an acceptable alternative.

   The plant can be maintained in a safe hot standby condition while any necessary manual actions are taken. The plant is capable of being cooled via natural circulation and reaching Residual Heat Removal System (RHRS) operation conditions within 36 hours including the time required to perform any manual actions. See Sections II.1 and III.1 as provided below.

3. Provide the capability to depressurize the Reactor Coolant System with only safety grade systems assuming a single failure and loss of offsite power or show that manual actions inside or outside containment or remaining at hot standby until manual actions or repairs are complete provides an acceptable alternative.

   The plant can be maintained in a safe hot standby condition while any required manual actions are taken. See Section II.3 (Cold Shutdown Scenario-depressurization) and Section III.3 (Single Failure Evaluation - Depressurization) as provided below.

4. Provide the capability for borating with only safety grade systems assuming a single failure and loss of offsite power or show that manual actions inside or outside containment or remaining at hot standby until manual actions or repairs are completed provides an acceptable alternative.

   The plant can be maintained in a safe hot standby condition while any required manual actions are taken. See Section II.2 (Cold Shutdown Scenario - Boration and Inventory Control) and Section III.2 (Single Failure Criterial - Boration and Inventory Control) as provided below.

5. Provide the system and component design features necessary for the prototype testing of both the mixing of the added borated water and cooldown under natural circulation conditions with and without a single failure of a steam generator atmospheric dump valve. These tests and analyses will be used to obtain information on cooldown times and the corresponding auxiliary feedwater (AFW) requirements.

   The plant design provides the capability for conducting natural circulation cooldown tests if required. However, the CPNPP test program does not include tests to verify boration or cooldown under natural circulation conditions since a utility is permitted to satisfy the testing requirement of the BTP through a comparison of plant systems of previously tested plants of a similar design. The natural circulation evaluation provided here presents a comparison of CPNPP Units 1 and 2 with Diablo Canyon Unit 1 to show that the natural circulation tests performed at Diablo Canyon are representative of the natural circulation cooldown, depressurization and boron mixing capabilities at CPNPP. The Diablo Canyon test results indicated that natural circulation flow rates were adequate to ensure that core decay heat removal, boron mixing and plant cooldown/depressurization were maintained throughout the test. The response of RCS temperatures indicated stable natural circulation conditions existed throughout the test.

6. Commit to providing specific procedures for cooling down using natural circulation and submit a summary of these procedures.

   Procedures for cooling down using natural circulation have been prepared; they were developed in accordance with applicable criteria of Regulatory Guide 1.33. These procedures are based upon generic Westinghouse Owners' Group Emergency Response Guidelines and contain plant specific information where applicable. A summary of the required actions is provided in Section II and Section III, below.

7. Provide a seismic Category I AFW supply for a least 4 hours at Hot Shutdown plus cooldown to the RHR system cut-in based on the longest time (for only onsite or offsite power and assuming the worst single failure), or show that an adequate alternate seismic Category I source will be available.

   Sufficient emergency feedwater is provided in the Seismic Category I condensate storage tank to permit four hours operation at hot standby plus cooldown to RHRS initiation conditions. In addition, a long term source of auxiliary feedwater is

provided by a connection to the Seismic Category I Service Water System. See Sections II.1 and III.1, as provided below.

8. Provide for collection and containment of RHR pressure relief or show that adequate alternative methods of disposing of discharge are available.

   The RHR relief valves discharge to the pressurizer relief tank, located inside containment.

II. COLD SHUTDOWN SCENARIO

The safe shutdown design basis of CPNPP is hot standby. The cold shutdown capability of the plant has been evaluated in order to demonstrate how the plant can be maintained in a safe hot standby condition while necessary manual actions are taken to achieve cold shutdown conditions following a safe shutdown earthquake, loss of offsite power, and the most limiting single failure. Under such conditions, the plant is capable of achieving RHRS operation conditions (approximately 350°F, 425 psia) in approximately 36 hours. To achieve and maintain cold shutdown, the following key functions must be performed: 1) residual heat removal, 2) boration and inventory control, and 3) depressurization.

1. Residual Heat Removal

   The function of residual removal is performed in two stages in accomplishing the cooldown from hot standby to cold shutdown.

   The first stage is from hot standby to 350°F. During this stage, circulation of the reactor coolant is provided by natural circulation with the reactor core as the heat source and the steam generators as the heat sink. Steam is initially released via the steam generator safety valves to maintain a hot standby. This occurs automatically as a result of turbine and reactor trip. Steam release for cooldown occurs via the steam generator power-operated atmospheric relief valves. As the cooldown proceeds, the operator adjusts these valves to increase the amount of steam dump, to permit a reasonable cooldown rate. Feedwater makeup is provided by the Auxiliary Feedwater System.

   The steam generator safety valves are Seismic Category I spring-loaded valves that can automatically maintain the plant in a safe hot standby for an extended period of time. The steam generator power-operated atmospheric relief valves are also seismically qualified. The control grade plant air supply system that powers these valves can be loaded on the emergency train A bus. Should a seismic event result in the loss of the air supply system, motive power for the PORV's is available from the seismically qualified air supply bottles. The steam generator power operated relief valves may be operated by means of manual handwheel operators when the air supply is exhausted. Should a single failure render one of the PORV's inoperable, the plant could be cooled down to the RHRS initiation temperature via one of the three active loops. Additionally the manual valve upstream of the failed PORV could be closed while the failed valve was repaired or replaced.

The Auxiliary Feedwater System is comprised of two separate Seismic Category I subsystems with sufficient alignment capability and flow capacity to ensure that feedwater can always be provided to all four generators. The first subsystem is comprised of two motor-driven pumps each powered from a different emergency power train. The two pumps and associated piping are normally isolated from each other and each is dedicated to two of the four steam generators. Operator action could be taken to open the normally closed isolation valves enabling either pump to provide feedwater to any of the four steam generators. The second subsystem incorporates a turbine-driven pump which can receive motive steam from either of two steam generators and can supply feedwater to all four steam generators.

The Auxiliary Feedwater System is capable of providing feedwater for an extended period of time. The primary source of feedwater is the Seismic Category I condensate storage tank (see Section 10.4.7.2 for additional details). There are additional sources of backup feedwater which can be manually accessed. Initial backup is provided by the Demineralized and Reactor Makeup Water System. Ultimate backup is from the Seismic Category I service Water System. In the unlikely event that sufficient auxiliary feedwater was not available in the condensate storage tank to complete the cooldown to RHR cut-in conditions, switchover to backup sources of water would be performed by the operator upon receipt of the condensate storage tank low level signal.

The status of each steam generator can be monitored using Class 1E instrumentation located in the Control Room. Separate indication channels for both steam generator pressure and water level are available. Operation of the Auxiliary Feedwater System can be monitored using Class 1E instrumentation located in the control room. This includes indication of the flows into each steam generator, the operating status light for the motor-driven pumps, and condensate storage tank level indication. There is also local indication of the turbine-driven pump suction and discharge pressure.

The second stage of cooldown is from 350°F to cold shutdown. During this stage, the RHRS is brought into operation. Circulation of the reactor coolant is provided by the RHR pumps and the heat exchangers in the RHRS act as the means of heat removal from the RCS. In the RHR heat exchangers, the residual heat is transferred to the Component Cooling Water System which ultimately transfers the heat to the Service Water System.

The RHRS is a fully redundant system. Each RHR subsystem includes a RHR pump and a heat exchanger. Each RHR pump is powered from different emergency power trains and each RHR heat exchanger is cooled by a different Component Cooling Water System loop. The Component Cooling Water and the Service Water Systems are both designed to Seismic Category I. If any component in one of the RHR subsystems were rendered inoperable as the result of a single failure, cooldown of the plant would not be compromised; however, the time for cooldown would be extended. The operation of the RHRS can be monitored using Class IE instrumentation in the Control Room.

There is indication of the pump discharge flow, the pump operating status and the component cooling flow from the discharge of the RHR heat exchangers.

2. Boration and Inventory Control

Boration is accomplished using portions of the Chemical and Volume Control System (CVCS). The boric acid transfer pumps supply four weight percent (7000 ppm) boric acid from the boric acid tanks to the suction of the centrifugal charging pumps which inject into the Reactor Coolant System (RCS) via the normal charging, safety injection auxiliary pressurizer spray, and/or reactor coolant pump seal injection flow paths. Makeup in excess of that required for boration can be provided from the refueling water storage tank (RWST) using paths as described for boration. Two motor-operated valves, different emergency diesels and connected in parallel, transfer the suction of the charging pumps to the RWST.

The boric acid transfer pumps and centrifugal charging pumps are train oriented and can be loaded on the emergency diesels. Should a common valve make both the normal and alternate charging lines unavailable, the reactor coolant pump seal injection flow would be sufficient for boration. The RCS can be borated to the cold shutdown concentration by accommodating the boration flow in the steam space of the pressurizer and in the space made available as the RCS shrinks due to cooling. Should this not be sufficient to accommodate all additions to RCS inventory, an alternative means of letdown would be via the reactor vessel head vent system.

Boration and makeup can be monitored using Class 1E instrumentation in the Control Room. Indications available include boric acid transfer and centrifugal charging pump operating status and boric acid tank and RWST level. Sampling can be done intermittently from several sampling connections in the normal letdown path, if it is available, or from two separate RCS hot legs. In the worst case situation, the amount of boron injected can be calculated by monitoring the inventory in the boric acid tanks.

3. Depressurization

Depressurization is accomplished using portions of the CVCS. Either four weight percent boric acid or refueling water can be used as desired for depressurization with the flow path being from the centrifugal charging pumps to the auxiliary spray valve to the pressurizer.

The centrifugal charging pumps of the CVCS are Seismic Category I, and can be powered by the emergency diesels.

Should the auxiliary spray valve fail to open following a seismic event, every effort would be made to open it. As an alternative, depressurization could be accomplished by discharging RCS inventory from the pressurizer via the pressurizer power-operated relief valves to the pressurizer tank (PRT). The design requirements of the PRT are provided in Section 5.4.11, Pressurizer Relief Discharge System. This operation can be integrated with the cooldown function

near the end of the cooldown to 350°F. As RCS inventory is relieved to the PRT, the pressurizer temperature and pressure is reduced, thus, reducing the pressure in the RCS. Make-up is provided as necessary to maintain a minimum level in the pressurizer. RCS pressure and temperature and pressurizer level can be monitored using Class 1E instrumentation in the Control Room.

4. Instrumentation

Class 1E instrumentation is available in the Control Room to monitor the key functions associated with achieving cold shutdown. This instrumentation is discussed in Section 7.5 and includes the following:

a. RCS wide range temperature

b. RCS wide range pressure

c. Pressurizer water level

d. Steam generator water level (per steam generator)

e. Steam line pressure (per steam line)

f. Condensate storage tank level

g. RWST level

h. Boric acid tank level (per boric acid tank)

i. Reactor building pressure

This instrumentation is sufficient to monitor the key functions associated with cold shutdown and to maintain the RCS within the desired pressure, temperature and inventory relationships. Operation of the auxiliary systems that service the RCS can be monitored by the Control Room operator, if desired, via remote communication with an operator in the plant.

5. Maintaining RCS Temperature and Pressure During Cooldown

The plant is maintained in a hot standby condition while the operator evaluates the initial plant conditions and the availability of equipment and systems (including non-safety grade equipment) that can be used in shutdown. Prior to initiating cooldown, the operator will determine the boration requirements and the method by which the plant can be taken to cold shutdown. In performing the cooldown, the operator integrates the functions of heat removal, boration and makeup, and depressurization, attempting to accomplish these functions without letdown from the RCS. Once the plant is cooled to 350°F and depressurized to 425 psig, RHRS operation is initiated and the RCS is taken to cold shutdown conditions.

Boration, cooldown, and depressurization is accomplished in a series of short steps arranged to keep RCS temperature and pressure and pressurizer level in

the desired relationships. However, to demonstrate that boration and depressurization can be done without letdown, a simpler scenario can be used. First, the operator integrates the cooldown and boration functions, taking advantage of the steam space available in the pressurizer and the RCS inventory contraction resulting from the cooldown. Then the operator uses auxiliary spray from the CVCS to depressurize the plant to RHRS initiating conditions. Finally, the RCS is cooled to cold shutdown using the RHRS and continuing to make up with borated water.

The calculation to demonstrate this capability assumes worst case boration requirements based on core end-of-life/peak xenon conditions and the following RCS initial conditions following plant trip:

RCS Temperature	557°F
RCS Pressure	2250 psia
Pressurizer Water Volume	450 ft^3
Pressurizer Steam Volume	1350 ft^3

The cooldown from 557°F to 350°F decreases the volume of water in the RCS by approximately 1620 cubic feet. This assumes that the pressurizer is not cooled and the water level is maintained at the initial condition. Makeup for contraction is supplied by four weight percent boric acid stored in the boric acid tanks. A boric acid tank volume of approximately 1460 cubic feet expands to approximately 1620 cubic feet as it is heated to the RCS temperature at 350°F assuming an initial tank temperature of 70°F. The volume required for boration at 350°F, to maintain the reactor within the technical specification shutdown requirements, is less than the contraction volume available at 350°F.

To calculate if depressurization can be accomplished without letdown and without taking the plant water solid, it is assumed that the pressurizer is at saturated conditions with 450 cubic feet of water, 1350 cubic feet of steam, and the pressurizer metal all at 653°F (2250 psia). It is further assumed that no additional water is removed from the pressurizer by the cooldown contraction. With these assumptions, and including the effect of heat input from the pressurizer metal, spraying in approximately 620 cubic feet of 70°F water produces saturated conditions at 425 psia (450°F) with a water volume of 1250 cubic feet and a steam volume of 550 cubic feet.

Once depressurized to RHR operational pressure, RHRS operation is initiated and cooldown is continued to cold shutdown conditions. The cooldown from 350°F to 200°F further decreases the volume of water in the RCS by approximately 550 cubic feet. This assumes that the pressurizer is not cooled and the pressurizer water level is maintained at the level resulting from depressurization. Makeup for contraction is again supplied by four weight percent boric acid from the boric acid tank volume of approximately 530 cubic feet as it is heated to the RCS temperature of 200°F. The additional volume required for boration at 200°F, approximately 260 cubic feet of four weight percent boric acid

which expands to approximately 270 cubic feet, is less than the additional contraction volume available at 200°F. This illustrates the technical specification requirements for cold shutdown conditions are satisfied.

The results of the calculation described above demonstrate that, based on the assumed initial conditions, boration and depressurization can be accomplished without letdown and without taking full credit for the available volume created by the cooldown contraction. Should boration without letdown prove impractical due to any combination of plant conditions or equipment failure, the operator could initiate the alternate methods of boration and or depressurization, i.e., boration could be accommodated via letdown through the reactor vessel head vent line and depressurization could be accomplished by discharging RCS inventory via the pressurizer power-operated relief valves to the PRT.

III. SINGLE FAILURE EVALUATION

1. Residual Heat Removal

A. From Hot Standby to 350°F

*Reactor coolant loops and steam generator - Four reactor coolant loops and steam generators are provided, any one of which can provide natural circulation flow for adequate core cooling. Even with the most limiting single failure (of a steam generator power-operated relief valve), three of the reactor coolant loops and steam generators remain available.

*Steam generator power-operated atmospheric relief valves - Four valves are provided (one per generator), any one of which is sufficient for residual heat removal. In the event of a single failure, three power-operated relief valves remain available.

*Auxiliary feedwater pumps - Two motor driven and one steam driven auxiliary feedwater pumps are provided. In the event of a single failure, adequate pumps remain available to provide sufficient feedwater. A pump can be aligned to provide water to all steam generators.

*Auxiliary feedwater flow control valves - Air-operated, fail open valves are provided. In the event of a single failure of one flow control valve (which affects flow to one steam generator from either a motor-driven pump or the steam-driven pump), auxiliary feedwater can still be provided to all four steam generators from the other pumps.

*Condensate storage tank - Upon depletion of the primary source of auxiliary feedwater in the Seismic Category I condensate storage tank, a backup source of auxiliary feedwater can be supplied from either train of the Seismic Category I Service Water System. (See Section II.1).

B. From 350°F to Cold Shutdown

*RHR pumps 1 and 2 - Two RHR pumps are provided, either one of which can provide adequate circulation of the reactor coolant. Each pump is powered from a different emergency power train. In the event of a single failure, either pump can provide sufficient RHR flow.

*RHR suction isolation valves 8701A and 8702A (to RHR pump 1) and 8701B and 8702B (to RHR pump 2) - The two valves in each RHR subsystem are each powered from different emergency power trains. Failure of either power train can prevent initiation of RHR cooling in the normal manner. In the event of such a failure, the affected valves(s) can be deenergized and opened with its handwheel or can be opened using alternate power via programmed operator action outside of the control room. Any other single failure can be tolerated as it would only affect one of the RHR subsystems and adequate cooling can be provided by the redundant subsystem.

*RHR heat exchanger 1 and 2 - If either heat exchanger is unavailable for any reason, the remaining heat exchanger can provide sufficient heat removal capability.

*RHR flow control valves HCV-606 and HCV-607 - If either of these normally open, fail open valves closes spuriously sufficient RHR cooling can be provided by the unaffected RHR subsystem.

*RHR/Safety Injection System cold leg isolation valves 8809 A and B - If either of these normally open, motor-operated valves, which are powered from different emergency power trains, closes spuriously, sufficient RHR cooling can be provided by the unaffected RHR subsystem. The affected valve can be deenergized and opened with its handwheel.

*Component Cooling Water System - Two redundant subsystems are provided for safety-related loads. Either subsystem can provide sufficient heat removal via one of the RHR heat exchangers.

*Service Water System - Two redundant subsystems are provided for safety-related loads. Either subsystem can provide sufficient heat removal via one of the Component Cooling Water System heat exchangers.

2. Boration and Inventory Control

*Boric Acid Tanks 1 and 2 - Two boric acid tanks are provided. Each tank contains sufficient four weight percent boric acid to borate the RCS for cold shutdown.

*Boric Acid Transfer Pumps 1 and 2 - Each pump is powered from a different emergency power train. In the event of a single failure, either pump can provide sufficient boric acid flow.

*Isolation Valve 8104 - If valve 8104, which is supplied from emergency power and is normally closed, cannot be opened due to power train or operator failure, it can be opened locally with its handwheel. If valve 8104 cannot be opened with its handwheel, an alternate flow path is available via a) air-operated, fail open valve FCV-110A and normally closed manual valve 8439 or b) gravity feed through normally closed manual valves 8507 and 8509.

*Refueling Water Storage Tank Isolation Valves LCV-112D and LCV-112E - Each valve is powered from a different emergency power train; only one of these normally closed motor-operated valves needs to be opened to provide a makeup flow path from the RWST to the centrifugal charging pumps.

*Centrifugal Charging Pumps 1 and 2 - Pumps 1 and 2 are powered from a different emergency power train. In the event of a single failure, any one pump can provide sufficient boratin or makeup flow.

*Flow Control Valve FCV-121 - This normally open valve fails open on loss of air. If FCV-121 closes spuriously, the centrifugal charging pumps can safely operate on their miniflow circuits. Efforts would be made to open it. The charging flow could be aligned to the RCS using the safety injection pathway, via valves 8801 A/B. Alternately, boration can be accomplished by starting the positive displacement charging pump.

*Normal Charging Flow Control Valve HCV-182 - This normally open valve fails open on loss of air or power. If HCV-182 closes spuriously, the charging pumps can operate on their miniflow circuits until operator action can open bypass valve 8403.

*Normal Charging Isolation Valves 8105 and 8106 - If either of these normally open, motor-operated valves, each of which is powered from a different emergency power train, closes spuriously, operator can be used to deenergize the valve operator and reopen the valve with its handwheel.

*Alternate Charging Isolation Valve 8402A - If this normally open motor-operated valve closes spuriously, operator action can be used to deenergize the valve operator and reopen the valve with its handwheel.

*Normal Charging Isolation Valve 8146 - If this normally open valves closes spuriously, alternate charging valve 8147, which fails open, can be used.

*Reactor Coolant Pump Seal Injection Valves 8351 A, B, C and D - If any of these normally open, motor-operated valves closes spuriously, operator action can be used to deenergize the valve operator and reopen the valve with its handwheel.

*Reactor Vessel Head Vent - This path provides an alternative means of letdown to accommodate the addition to RCS inventory during boration, i.e., if it cannot be accommodated by system shrinkage.

3. Depressurization

*Auxiliary Spray Valve - This normally closed valve fails closed on loss of air. If 8145 is struck closed as a result of a single failure, the redundant pressurizer power-operated relief valves can be used to depressurize the RCS by discharging the pressurizer inventory to the pressurizer relief tank.

*Charging Valves 8146 and 8147 - These valves fail open on loss of air decreasing the effectiveness of the auxiliary pressurizer spray. If either is struck open, the redundant pressurizer power-operated relief valves can be used to depressurize the RCS by discharging the pressurizer inventory to the pressurizer relief tank.

*RHR Suction Isolation Valve 8701 A and B and 8702 A and B - The RHR suction isolation valves are qualified for the steam line break environment. Therefore, they are qualified for the less severe environment that would result if, as described in the above A and B, the RCS is depressurized by discharging the pressurizer inventory to the pressurizer relief tank.

4. Instrumentation

Sufficient instrumentation is provided to monitor from the Control Room the key functions associated with cold shutdown. All necessary indications are redundant. Thus, in the event of a single failure, the operator can make comparisons between duplicate information channels or between functionally related channels in order to identify the particular malfunction. Refer to Section 7.5 for applicable details.

IV. NATURAL CIRCULATION

Comanche Peak Unit 1 and Unit 2 and Diablo Canyon Unit 1 have been compared in detail to ascertain any differences between the two plants that could potentially affect natural circulation flow and attendant boron mixing. Because of the similarity between the plants, it was concluded that the natural circulation capabilities would be similar, and, therefore, the results of the natural circulation cooldown tests conducted at Diablo Canyon are representative of the capability at Comanche Peak.

The general configuration of the piping and components in each reactor coolant loop is the same in both Comanche Peak and Diablo Canyon. The elevation head represented by these components and the system piping is similar in both plants.

To compare the natural circulation capabilities of Comanche Peak and Diablo Canyon, the hydraulic resistance coefficients were compared. The hydraulic resistance coefficients applicable to normal flow conditions are as follows:

	Diablo Canyon Unit 1	Comanche Peak	
	($X10^{-10}$ft/(GPM)^2)	($X10^{-10}$ft/(GPM)^2)	
		Unit 1[a]	Unit 2
Reactor Core and Internals	129.0	110.2	116.0
Reactor Nozzles	36.1	27.2	27.2
RCS Piping	20.9	25.1	25.1
Steam Generator	112.0	112.4[b]	114.1
Total Hydraulic Resistance Coefficients	298.0	274.8[c]	282.4

a) Values for Steam Generator and Total Hydraulic Resistance Coefficients have been determined for the Unit 1 Δ76 Replacement Steam Generator (RSG) (feedring design).

b) The Unit 1 RSG values are 94.9 and 112.7 for 0% and 10% SGTP respectively.

c) The Unit 1 RSG values are 257.4 and 275.2 for 0% and 10% SGTP respectively.

The flow ratio of Comanche Peak to Diablo Canyon is proportional to the square root of the inverse of the resistance coefficients.

Flow Ratio:

$$\frac{\text{Comanche Peak Unit 1}}{\text{Diablo Canyon}}\left[\frac{298.0}{274.8}\right]^{1/2} = 1.0414 \quad \text{Unit 1 old SG}$$

$$\frac{\text{Comanche Peak Unit 2}}{\text{Diablo Canyon}}\left[\frac{298.0}{282.4}\right]^{1/2} = 1.0272$$

RSG 0% SGTP

$$\frac{\text{Comanche Peak Unit 1 RSG}}{\text{Diablo Canyon}}\left[\frac{298.0}{257.4}\right]^{1/2} = 1.0760$$

RSG 10% SGTP

$$\frac{\text{Comanche Peak Unit 1 RSG}}{\text{Diablo Canyon}}\left[\frac{298.0}{275.2}\right]^{1/2} = 1.0406$$

Note: The hydraulic resistance and the natural circulation flow thermal driving head for the Comanche Peak Unit 1 RSGs (Δ76 SGs) are comparable to those of the old

Model D4 steam generators. Therefore the RSGs will have no adverse impact on the natural circulation cooling capability of the plant [1].

The general arrangement of the reactor core and internals is the same for Comanche Peak and Diablo Canyon. The slight variation in the hydraulic resistance coefficient is primarily due to the specific design details of the vessel and internals (i.e., flow area, upper/lower support plate designs, thermal design flow, elevations, etc.).

The reactor vessel outlet nozzle configuration for both plants is the same. The radius in curvature between the vessel inlet nozzle and downcomer section of the vessel in the two plants is different. Based on 1/7 scale model testing performed by Westinghouse, the radius on the vessel nozzle/vessel downcomer juncture influences the hydraulic resistance of the flow turning from the nozzle to the downcomer. The Diablo Canyon vessel inlet nozzle radius is significantly smaller than that of Comanche Peak as reflected by the higher coefficient for Diablo Canyon.

The resistance coefficient for the RCS piping for both plants is similar, as reflected in the resistance coefficients previously tabulated.

Steam generator units were also compared to ascertain any variation that could affect natural circulation capability by changing the effective elevation of the heat sink or the hydraulic resistance seen by the primary coolant. The Comanche Peak design utilizes a Model D4 (Unit 1) and D5 (Unit 2) steam generator design while the Diablo Canyon design utilizes a Model 51. The major design differences between the generators are that the Model D4 and D5 incorporate a preheater in the lower tube bundle region and the tube bundle elevation is shorter than that of the Model 51. For the natural circulation conditions present, the presence of the preheater unit has negligible effects on flow conditions because auxiliary feedwater flow does not pass directly through the preheater. The differences of tube bundle elevations has an effect on the natural circulation driving head established by the system. The longer tube bundle in the Model 51 SG for Diablo Canyon Unit 1 would result in approximately a 6.3 ± 2.5% (3.8 to 8.8%) higher driving head when compared to the Model D4 or D5 SGs installed at Comanche Peak. This variance in net driving head is relatively small and should not significantly affect the natural circulation flow rate. The heat transfer area between the two generators is also very similar. Even though the Model D4 and D5 have a shorter tube bundle elevation, they have a greater number of tubes as compared to the Model 51. This increase in the number of tubes offsets the shorter tube bundle length of the D4/D5 steam generators with respect to heat transfer area. Additionally, the RCP impeller designs for each plant were also considered to determine any impact on natural circulation flow. The impeller designs are similar for the Diablo Canyon and Comanche Peak RCPs. However, it is noted that the RCP loss coefficients are slightly different. The effects of the slight differences in the driving heads and RCP loss coefficients are quantified below.

As indicated, the overall hydraulic loss coefficient (excluding RCPs) for Comanche Peak is lower than that of Diablo Canyon. It is expected that the relative effect of the coefficients seen would be the same under natural circulation conditions. Therefore, based on the flow ratio correlation utilizing the total hydraulic loss coefficient for each plant (and excluding the differences in driving heads and RCP loss coefficients), the Comanche Peak units will have a natural circulation flow rate approximately 2 - 4% higher than of that for Diablo Canyon. If the slight differences in the thermal driving head and

RCP flow resistance (as detailed previously) are accounted for, the natural circulation flow rate for Comanche Peak will be approximately 4% lower than that for Diablo Canyon. A Comanche Peak natural circulation flow of this magnitude will be sufficiently similar to that obtained for Diablo Canyon such that the Diablo Canyon natural circulation test results are applicable to Comanche Peak.

The data provided above reflects the flowrate and associated heat removal capability of an individual loop in the plant. The comparison, therefore, does not take into consideration the number of loops available nor the core heat to be removed. An evaluation of the Comanche Peak steam relief and auxiliary feedwater systems has been performed to demonstrate that cooling can be provided via three steam generators following the most limiting single active failure, i.e., the failure of an atmospheric relief valve.

Loop circulation flow is dependent on reactor core decay heat which is a function of time based on core rating and its power operating history. Under natural circulation flow conditions, flow into the upper head area will constitute only a small percentage of the total core natural circulation flow and therefore will not result in an unacceptable reduction in the natural circulation flow required to cool the core.

For typical 4-loop plants there are two potential flow paths by which flow crosses the upper head region boundary in a reactor. These paths are the head cooling spray nozzles, and the guide tubes. The head cooling spray nozzle is a flow path between the downcomer region and the upper head region. The temperature of the flow which enters the head via this path corresponds to the cold leg value (i.e., T_{cold}). Fluid may also be exchanged between the upper plenum region (i.e., the portion of the reactor between the upper support plate) and the upper head region via the guide tubes.

Guide tubes are dispersed in the upper plenum region from the center to the periphery. Because of the nonuniform pressure distribution at the upper core plate elevation and the flow distribution in the upper plenum region, the pressure in the guide tube varies from location to location. These guide tube pressure variations create the potential for flow to either enter or exit the upper head region via the guide tubes.

To ascertain any difference between the upper head cooling capabilities between Diablo Canyon and Comanche Peak a qualitative comparison is made. Since Comanche Peak is a Tcold plant, the upper head region is expected to cool at a rate comparable to or exceeding that of Diablo Canyon. Due primarily to differences in the upper support plate design between the two plants, the upper head region for Comanche Peak is approximately 87% larger than that of Diablo Canyon. The reactor vessel spray nozzles between the downcomer and upper head region have a flow area more than 10 times larger for Comanche Peak (vs. Diablo Canyon) providing the enhanced flow mixing capability which maintains the upper head region at a temperature near the cold leg temperature. Therefore, adequate upper head cooling for Comanche Peak is expected during a natural circulation cooldown scenario.

BORON MIXING

A boron mixing calculation has been performed for Comanche Peak to determine the time necessary, under natural circulation conditions, to achieve an increase in RCS boron concentration similar to that exhibited by Diablo Canyon Unit 1 during the natural circulation boron mixing test (i.e., 300 ppm). The calculation assumes no let down and the normal charging line plus the RCP seals provide the boron injection paths at a total boration rate of 75 gpm. For Comanche Peak, boron will normally be supplied from the 7000 ppm (minimum) boron solution of the boric acid tanks to the suction of the centrifugal charging pumps by the boric acid transfer pumps. Makeup in excess of that needed for boration can be provided from the RWST. The results of the calculation indicate that a time of approximately one (1) hour is needed to achieve a 300 ppm increase to the initial RCS boron concentration. The BAT is adequately sized to provide this quantity of borated water.

Conclusion

Based on the above evaluations, it can be concluded that the results of the natural circulation cooldown tests performed at Diablo Canyon are representative of the natural circulation and boron mixing capability of Comanche Peak. Therefore, the Comanche Peak units satisfy the test requirements of Branch Technical Position RSB 5-1 via this comparison.

References

1. Westinghouse report, WCAP-16469-P, Rev. 1, Comanche Peak Unit 1 Replacement Steam Generator Program NSSS Engineering Report, June 2006 (VL-06-001760).

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6.1N ENGINEERED SAFETY FEATURE MATERIALS

6.1N.1 METALLIC MATERIALS

6.1N.1.1 Materials Selection and Fabrication

Typical materials specifications used for components in the engineered safety features (ESF) are listed in Table 6.1N-1. In some cases, this list of materials may not be totally inclusive. However, the listed specifications are representative of those materials used. Materials utilized are procured in accordance with the materials specification requirements of the American Society of Mechanical Engineers (ASME) Code, Section III, plus applicable and appropriate addenda and code cases.

The welding materials used for joining the ferritic base materials of the ESF conform to or are equivalent to ASME Material Specifications SFA 5.1, 5.2, 5.5, 5.17, 5.18, and 5.20. The welding materials used for joining nickel-chromium-iron alloy in similar base material combination and in dissimilar ferritic or austenitic base material combination conform to ASME Material Specifications SFA 5.11 and 5.14. The welding materials used for joining the austenitic stainless steel base materials conform to ASME Material Specifications SFA 5.4 and 5.9. These materials are tested and qualified to the requirements of the ASME Code, Section III and Section IX rules and are used in procedures which have been qualified to these same rules. The methods utilized to control delta ferrite content in austenitic stainless steel weldments are discussed in Section 5.2.3.

All parts of components in contact with borated water are fabricated of or clad with austenitic stainless steel or equivalent corrosion resistant material. The integrity of the safety-related components of the ESF is maintained during all stages of component manufacture. Austenitic stainless steel is utilized in the final heat treated condition as required by the respective ASME Code, Section II, material specification for the particular type or grade of alloy. Furthermore, it is required that austenitic stainless steel materials used in the ESF components be handled, protected, stored, and cleaned according to recognized and accepted methods which are designed to minimize contaimination which could lead to stress corrosion cracking. The rules covering these controls are stipulated in Westinghouse process specifications, which are discussed in Section 5.2.3. Additional information concerning austenitic stainless steel, including the avoidance of sensitization and the prevention of intergranular attack, can be found in Section 5.2.3. No cold worked austenitic stainless steels having yield strengths greater than 90,000 pounds per square inch (psi) are used for components of the ESF within the Westinghouse standard scope.

Westinghouse supplied ESF components within the Containment that would be exposed to core cooling water and containment sprays in the event of a loss of coolant accident (LOCA) utilize materials listed in Table 6.1N-1. These components are manufactured primarily of stainless steel or other corrosion resistant, high temperature material. The integrity of the materials of construction for ESF equipment when exposed to post design basis accident (DBA) conditions has been evaluated. Post DBA conditions were conservatively represented by test conditions. The test program [1] performed by Westinghouse considered spray and core cooling solutions of the design chemical compositions, as well as the design chemical compositions contaminated with corrosion and deterioration products which may be transferred to the solution during recirculation. The effects of sodium (free caustic), chlorine (chloride), and fluorine (fluoride) on austenitic stainless steels were considered. Based on the results of this investigation, as well as

testing by Oak Ridge National Laboratory (ORNL) and others, the behavior of austenitic stainless steels in the post DBA environment will be acceptable. No cracking is anticipated on any equipment even in the presence of postulated levels of contaminants, provided the core cooling and spray solution pH is maintained at an adequate level. The inhibitive properties of alkalinity (hydroxyl ion) against chloride cracking and the inhibitive characteristic of boric acid on fluoride cracking have been demonstrated. Coatings on exposed surfaces within the Containment are not subject to breakdown under exposure to the spray solution and can withstand the temperature and pressure expected in the event of a LOCA.

Information concerning the degree to which the materials used comply with Regulatory Guides 1.31, 1.37, and 1.44 can be found in Appendix 1A(N).

6.1N.1.2 Composition, Compatibility, and Stability of Containment and Core Spray Coolants

The only Westinghouse supplied vessels used for storing ESF coolants, are the accumulators.

The accumulators are carbon steel clad with austenitic stainless steel. Because of the corrosion resistance of these materials, significant corrosive attack on the storage vessels is not expected.

The accumulators are vessels filled with borated water and pressurized with nitrogen gas. The nominal boron concentration, as boric acid, is provided in Table 6.1B-4. Samples of the solution in the accumulators are taken periodically for checks of boron concentration. Principal design parameters of the accumulators are listed in Table 6.3-1.

The method of establishing containment spray and recirculation sump pH following a LOCA is discussed in Sections 6.2.2 and 6.2.3. Information concerning hydrogen release by the corrosion of containment metals and the control of the hydrogen and combustible gas concentrations within the containment following a LOCA is discussed in Section 6.2.5.

6.1N.2 ORGANIC MATERIALS

Protective coatings for use in the reactor containment have been evaluated as to their suitability in post DBA conditions. Tests have shown that the epoxy and modified phenolic systems are the most desirable of the generic types evaluated for in Containment use. This evaluation considered resistance to high temperature and chemical conditions anticipated following a LOCA, as well as high radiation resistance [2]. Information regarding compliance with Regulatory Guide 1.54 can be found in Appendix 1A(N).

6.1N.3 POSTACCIDENT CHEMISTRY

Refer to Section 6.1B.3.

REFERENCES

1. "Behavior of Austenitic Stainless Steel in Post Hypothetical Loss of Coolant Accident Environment," WCAP-7798-L (Proprietary) and WCAP-7803 (Non-Proprietary), January 1972.

2. "Evaluation of Protective Coatings for use in Reactor Containment," WCAP-7198-L (Proprietary), April 1969 and WCAP-7825 (Non-Proprietary), December 1971.

TABLE 6.1N-1
ENGINEERED SAFETY FEATURE MATERIALS

(Sheet 1 of 2)

Valves	
Bodys	SA-182, Type F316 or SA-351, Gr. CF8 or CF8M
Bonnets	SA-182, Type F316 or SA-351, Gr. CF8 or CF8M
Discs	SA-182, Type F316 or SA-564, Gr. 630 cond. 1100° heat treatment or SA-351, Dr. CF8 or CF8M
	A-567 Grade 1 (Stellite 21)
Pressure retaining bolting	SA-453, Gr. 660
Pressure retaining nuts	SA-453, Gr. 660 or SA-194, Gr. 6
Auxiliary Heat Exchangers	
Heads	SA-240, Type 304
Nozzle necks	SA-182, Gr. F304; SA-312, Type 304 SA-240, Type 304
Tubes	SA-213, Type 304; SA-249, Type 304
Tubesheets	SA-182, Gr. F304; SA-240, Type 304 SA-516, Gr. 70 with Stainless Steel Cladding A-7 Analysis
Shells	SA-240 and SA-312 Type 304
Auxiliary Pressure Vessels, Tanks, Filters, etc.	
Shells and heads	SA-351, Gr. CF8A; SA-240, Type 304; SA-264 Clad Plate of SA-537, Gr. B with SA-240, Type 304 Clad and Stainless Steel Weld Overlay A-8 Analysis
Flanges and nozzles	SA-182, Gr. F304; SA-350, Gr. LF2 with SA-240, Type 304 and Stainless Steel Weld Overlay A-8 Analysis
Piping	SA-312 and SA-240, Type 304 or Type 316 Seamless
Pipe fittings	SA-403, Type 304 Seamless
Closure bolting and nuts	SA-193, Gr. B7 and SA-194, Gr. 2H

TABLE 6.1N-1
ENGINEERED SAFETY FEATURE MATERIALS

(Sheet 2 of 2)

Auxiliary Pumps	
Pump casing and heads	SA-182, Gr. F304
Flanges and nozzles	SA-182, Gr. F304
Stuffing or packing box cover	SA-182, Gr. F304
Closure bolting and nuts	SA-193, Gr. B6 and Gr. B7; SA-453, Gr. 600; and Nuts Gr. 6 and Gr. 7

6.1B ENGINEERED SAFETY FEATURE MATERIALS

6.1B.1 METALLIC MATERIALS

This section contains information concerning the materials used for the major pressure retaining components in the engineered safety features (ESF) not covered by Section 6.1N. The information provided presents acceptable means for the control of welding procedures, control of the use of sensitized stainless steel, and selection of materials with regard to their compatibility with specific fluids used.

The systems affected include the Containment Spray System (CSS) [2], [3], and Containment Isolation System. Tables 6.1B-1 and 6.1B-2 contain major components and material specifications for non-Westinghouse procured ESF systems.

Selection and procedures of the above system components materials are in compliance with the ASME B&PV Code, Section III. The control of delta ferrite in welding will comply with Subsections 6.1B.1.1.3 or 6.1B.1.1.4. Avoidance of sensitization will be in compliance with the recommendations of NRC Regulatory Guide [6] except for position C6. Intergrannular corrosion tests for each welding procedure will not be made because the control of weld heat input will be implemented as described in Subsection 6.1B.1.1.2, 1.e.

6.1B.1.1 Materials Selection and Fabrication

6.1B.1.1.1 Specification for Principal Pressure-Retaining Materials and ESF Construction Materials Exposed to Core Cooling and Containment Spray Water

The internal and external surfaces of the ESF components covered in this section are subjected to three types of core cooling and Containment spray water exposures:

1. Internal exposure only - components located outside the Containment

2. External exposure only - components located inside the Containment and not part of the ESF fluid systems

3. Internal and external exposure - components located inside the Containment and part of the ESF fluid systems

All materials used for the ESF components which are subjected to any type of core cooling or Containment spray water exposure, or both, are chosen to be corrosion resistant and their integrity and performance in other operating plants was satisfactory. A listing of construction materials for the ESF components (other than valves) is given in Table 6.1B-1.

Typical materials specifications used for valves in the engineered safety features (ESF) are listed in Table 6.1B-2. In some cases, this list of materials may not be totally inclusive. However, the listed specifications are representative of those materials used. All materials for pressure retaining components are procured in accordance with the ASME B&PV Code, Section III.

Criteria for pH level of postaccident emergency core cooling and Containment spray water established in Branch Technical Position MTEB 6-1 [12] are implemented in design of the CSS as discussed in Sections 6.2.2 and 6.5.2.

6.1B.1.1.2 Integrity of ESF Components

The following sections provide information pertaining to the integrity of the safety-related components of the ESF during all stages of component manufacture.

1. Avoidance of Sensitization

In order to limit the stress corrosion cracking in the unstabilized austenitic stainless steel materials Types 304 and 316 used for components and piping of safety-related systems, the following provisions are established:

a. Only the materials listed in Tables 6.1B-1 and 6.1B-2 are used.

They have been processed and fabricated using the methods described in this section to minimize local sensitization. In addition, all austenitic stainless steel materials are supplied in the solution-annealed condition as prescribed by the ASME B&PV Code, Section II.

For austenitic stainless steel materials of product forms with complex shapes which have inaccessible cavities or chambers that would preclude rapid cooling when water quenched a specimen from each heat treating procedure and each heat of material is intergranular corrosion tested in accordance with ASTM A 262-70, Practice A or E. This testing is not performed on product forms with simple shapes such as plates, sheets, bars, pipe, and tubes as well as forgings and castings with simple shapes which do not preclude rapid cooling.

b. The cleaning and contamination protection procedures, as described in Part 2 of this section, are applied to all surfaces of the austenitic stainless steel materials prior to any elevated temperature treatment and prior to hydrotests.

c. The material used is not subjected to sensitizing temperatures above 800°F during fabrication except for welding and hot bending. Hot bending is followed by solution annealing.

d. Welding is in compliance with ASME B&PV Code, Sections III and IX, using qualified welding procedures and welders.

e. In order to avoid sensitization in the heat affected zone, arc heat input of any weld bead will be calculated by the following formula and documented in the procedure qualification records:

$$H = \frac{E \times I \times 60}{S}$$

where

H = energy input, Joules/in.
E = welding voltage, V

I = welding current, A
S = travel speed, in./min

Energy input as determined by this formula is less than or equal to the following maximum values for the various welding processes shown:

Welding Process Method	Max. Energy Input (kJ/in.)
Manual shielded tungsten arc (GTAW)	50
Manual shielded metallic arc (SMAW)	120
Semiautomatic gas shielded metal arc (GMAW)	60
Automatic gas-shielded tungsten arc - hot wire (GTAW)	75
Automatic gas-shielded tungsten arc - cold wire[(a)] (GTAW)	45
Automatic submerged arc (SAW)	140
Flux-core welding	100

a) Except for specimens having essentially the same thickness, the weld procedures qualifications specimens for the cold wire GTAW process are corrosion tested on ASTM A 262-70, Practice E, [10] and will be so documented.

Exceptions to the control of weld are heat input are the two (2) Chemical Additive Tanks. The above criteria were not used in the welding of these tanks. Using written procedures, welds were simulated and then tested by an independent laboratory to Practice E of ASTM A-262. The heat affected zones were proven to be free of intergrannular corrosion attack.

As an alternate to the foregoing, the heat input for austenitic stainless steel welding shall be controlled by the following:

1. The welding procedure qualification shall include corrosion tests in accordance with ASTM A 262-70, Practice E as modified by Westinghouse P.S. 84201MW-MX Revision 3 dated November 28, 1973.

2. Interpass temperatures shall be limited to 350°F maximum.

3. Production welding shall be monitored for the essential variables listed in paragraph 4 following.

4. Welding parameters of maximum amperage, voltage and maximum bead width shall be considered essential variables and shall not be exceeded without requalification in accordance with (1) above.

f. Hardsurfacing

All hardsurfacing procedures are submitted for approval and are established to preclude sensitization of stainless steel components.

2. Cleaning and Contamination Protection Procedures

Stainless steel materials used for fabrication, installation, and testing of components that are part of the ESF systems are thoroughly cleaned and descaled.

Pickling and passivating during component fabrication will be used only if deemed necessary to ensure cleanliness. They are done in accordance with the practices recommended in ASTM A 380 [11]. The stainless steel materials are thoroughly cleaned including removal of any potentially harmful markings and coatings (adhesive paper, masking tape, or plastic coating) before any elevated temperature treatment and hydrotests.

When all cleaning solutions, processing compounds, degreasing agents, and other foreign materials are removed, austenitic stainless steel materials are protected against contaminants hazardous to austenitic stainless steel throughout the fabrication, shipment, storage, construction, testing, and operation of components.

Exceptions to this are two (2) Recycle Hold-up Tanks, and two (2) Boric Acid Storage Tanks. These items were not given the protection described during construction. Construction site personnel have cleaned and maintained the cleanness of the equipment mentioned in accordance with ANSI N45.2.1-1973 "Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants", Class B level.

The cleaning and contamination protection procedures and acceptance criteria are established in the stainless steel component design specifications as required by ASME B&PV Code, Section III, Appendix B.

Plugs and closures made from elastomers, plastics, wood, composite board, and metal of the same or compatible composition as the component are placed over all openings as protective covers to prevent contamination during storage and shipment.

3. Thermal Insulation

Within the Containment Building, stainless steel reflective metallic insulation is used to insulate the bulk of the piping.

The other types of insulation used inside the Containment Building are: anti-sweat insulation and high efficiency thermal insulation.

a. Anti-sweat insulation is used to prevent condensation from forming on cold lines. This insulation is composed of molded or resin bonded fiberglass with an outside vapor barrier.

b. High efficiency thermal insulation is used only on specific piping and is installed underneath u-bar pipe restraints and adjacent to high energy absorbing bumpers to reduce the acceleration gap and minimize the restraint loads. This insulation is composed of fibrous media and very fine heat resistant particulate matter totally encased in stainless steel.

Outside of the Containment, nonmetallic asbestos-free insulation composed of hydrous calcium silicate, anti-sweat or thermal fiberglass are used. All hydrous calcium silicate insulation and finishing cements are composed of calcium silicate mineral fibers and binders. Sodium silicate is added as required to meet fluoride and chloride content restrictions. All calcium silicate insulation is covered by an aluminum or stainless steel jacket. Antisweat or thermal fiberglass insulation, as previously described, is also used outside of the Containment.

A representative sample from each production lot shall undergo a chemical analysis to determine leachable chloride, fluoride, sodium, and silicate ion concentration as described in NRC Regulatory Guide 1.36. The lot shall be accepted if the requirements of NRC Regulatory Guide 1.36 [5] are met. In addition, each type of thermal insulation material shall also be qualified for use by a stress corrosion test to ensure that the insulation composition does not induce stress corrosion. Either of the following methods will be used:

a. ASTM C692-71, Evaluating Stress Corrosion Effect of Wicking-Type Thermal Insulations on Stainless Steel (Dana Test) [13]. The material shall be rejected if more than one of five specimens crack.

b. RDT M12-IT, Test Requirements for Thermal Insulating Materials for Use on Austenitic Stainless Steel, Section 5 (Knolls Atomic Power Laboratory, KAPL Test) [14]. The material shall be rejected if more than one of four specimens cracks.

All insulation materials will be adequately packaged and protected to prevent moisture pickup or contamination by external sources. Insulation will be stored in a clean, dry area.

Before the insulation is applied, all metal surfaces are adequately cleaned to remove unacceptable levels of harmful contaminents. Insulation which is wet or shows signs of having previously been wet is unacceptable for use.

6.1B.1.1.3 Control of Delta Ferrite

This section describes the method of implementing Appendix A, GDC 1 [1] and Appendix B of 10 CFR Part 50 with regard to control of welding of austenitic stainless steel and components and systems important to safety.

The welding materials used for production of weld joints must have a minimum of five percent delta ferrite (including consumable inserts).

The welding procedures and welder qualifications are determined according to ASME B&PV Code, Section IX, Welding Qualifications.

When the new welding procedure qualification tests are evaluated for these applications, including repair welding of materials, the following examinations are performed in addition to the requirements of ASME B&PV Code, Section III:

1. Chemical Analysis

   Actual chemical analysis is compared to the Shaeffler Diagram (American Society for Metals Handbook, Vol. 6, pp. 246-47) [15]. Samples will be taken from the undiluted weld metal.

2. Magne-gage method

   The determination of the delta ferrite content is made on undiluted weld metal using calibrated magnetic measuring devices conforming to the AWS A4.2-74, Standard Procedures for Calibrating Magnetic Instruments to Measure the Delta Ferrite Content of Austenitic Stainless Steel Weld Metal [16].

3. Macroscopic Examination

   A visual examination is performed on the procedure-qualification-tested bend specimens using 5 to 10 times magnification. In addition to the evaluation of open defects, the small fissures or cracks are observed and evaluated on the bases of their length and number per unit of area. This information is reported for the procedure qualification records.

4. Heat Input Control

   The procedure qualification record also includes the nonessential elements which affect the quality of a weld. The segregation and fissuring can be reduced if the temperature gradient, i.e., heat input, is kept low. Consequently, the procedure qualification records contain the calculation of the heat input using the nonessential elements as described in Subsection 6.1B.1.1.3.

5. Interpass Temperature Control

   The maximum interpass temperature in all welding processes is 350°F and is reported in the procedure qualification records.

6. Destructive and Nondestructive Testing

   The results of all the destructive and nondestructive tests are reported in the procedure qualification record in addition to the information required by ASME B&PV Code, Section III.

7. Welding Materials

   The welding materials used for production welds meet the requirements of Section III and Section II, Part C, of the ASME B&PV Code. According to ASME B&PV Code Section III,

bare weld filler metal (including consumable inserts) used in inert gas-welding process conforms to ASME SFA-5.9 and contains not less than five percent delta ferrite in the deposit.

Weld filler metal materials used in flux shielded welding processes conform to ASME SFA-5.4 or SFA-5.9 and are procured in a wire flux composition to be capable of providing not less than five percent delta ferrite in the deposit according to ASME B&PV Code, Section III.

8. Control of Production Welds

The welding procedures are qualified using nondestructive and destructive mechanical tests as specified in ASME B&PV Code, Sections III and IX. Both the essential and the nonessential variables are recorded and certified and are accessible to the authorized inspector.

The procedure qualification for stainless steel welding will record all the essential variables and in addition, the following:

a. Process variables such as slag pool depth and electrode feed rate oscillation

b. Welder performance qualifications, as required in ASME B&PV Code, Section IX, are determined and recorded. Those welders qualified to make austenitic stainless steel welds must follow the established welding procedures in order to ensure the minimum 5 percent of delta ferrite in production welds.

9. Quality Assurance

The welding quality assurance program includes identification and control of welding material by lots and heats as appropriate. All of the weld processing is monitored according to approved inspection programs, which include review of "starting" materials, qualification records, and welding parameters. Welding systems are also subject to quality assurance audit including calibration of gages and instruments, identification of "starting" and completed materials, welder and procedure qualifications, availability and use of approved welding and heat treating procedures, and documentary evidence of compliance with materials, welding parameters, and inspection requirements.

6.1B.1.1.4 Control of Delta Ferrite - Alternate Method

As an alternate to Subsection 6.1B.1.1.3, the control of delta ferrite will follow the recommendations of NRC Regulatory Guide 1.31, Revision 1 [4], or Revision 2 [4a].

An exception to this is the Containment Spray Pumps. In general, Revision 2 of Regulatory Guide 1.31 will apply in the control of delta ferrite. However, where welding was done prior to establishing the acceptability of the welding materials used, and where these materials are no longer available, determination of delta ferrite was made in accordance with position C5 of Regulatory Guide 1.31, Revision 1.

6.1B.1.2 Composition and Compatibility of Containment and Core Spray Coolants

The method of establishing and controlling Containment spray and recirculation sump pH following a loss-of-coolant accident (LOCA) is discussed in Sections 6.2.2 and 6.5.2. The method ensures a pH greater than 8.25 for all modes of operation of the spray system. Use of the alkaline spray enhances iodine removal and reduces the possibility of stress corrosion cracking of austenitic stainless steel. Use of metals, such as aluminum and zinc, which react with the alkaline spray forming hydrogen are carefully controlled. This use conforms to Branch Technical Position MTEB 6-1. Information concerning hydrogen release by the corrosion of Containment metals and other sources and control of hydrogen gas concentrations within the Containment following a LOCA is presented in Section 6.2.5.

Materials used for the Containment and for components therein are chosen for their compatibility with the spray solution (LOCA environment) and for their intended normal service. Materials used in the ESF system are chosen for their compatibility with the spray solution which consists of borated water and 30 percent sodium hydroxide. Details concerning the spray additive subsystem are discussed in Sections 6.2.2 and 6.5.2.

6.1B.2 ORGANIC MATERIALS

A list of organic materials used in the Containment is presented in Table 6.1B-3.

The significant coating systems used inside the containment are as follows:

	Primer	Finish
Steel	Inorganic Zinc	Epoxy
Concrete	Epoxy surfacer	Epoxy

The protective coatings program for ongoing Service Level I inspections, maintenance, repair and modifications is in accordance with the following guidance:

- EPRI Report 1003102, “Guideline on Nuclear Safety-Related Coatings”, Revision 1 (formerly TR-109937) [Ref. 7]

- ASTM D 5144-00, “Standard Guide for Use of Protective Coating Standards in Nuclear Power Plants. [Ref. 8]

A detailed “suitability of application review” of the protective coatings inside containment for Units 1 and 2 has been performed based on the guidance in EPRI Report 1003102 “Guideline on Nuclear Safety-Related Coatings”, Revision 1 (formerly TR-109937) and ASTM D 5144-00, Standard Guide for Use of Protective Coating Standards in Nuclear Power Plants. [Ref. 17]

ASTM D 3911-03, Standard Test Method for Evaluating Coatings Used in Light Water Nuclear Power Plants at Simulated Design Basis Accident (DBA) Conditions is followed in the evaluation of protective coating system test results. Testing of each coating system to a minimum of 3.0 E+08 Rads gamma is adequate for a Service Level I system to be qualified. However, testing of each coating system to a minimum of 2.0 E+08 Rads gamma is also adequate for a Service

Level I system to be qualified as long as the individual coatings have passed radiation tolerance testing equal to, or in excess of 3.0 E+08 Rads.

A specifically structured quality assurance program based on the guidance in EPRI Report 1003102 is applicable to the Service Level I coatings and program as described in Appendix 17A.

The Containment building coating systems are applied over surfaces prepared in accordance with approved procedures and the coating manufacturers' instructions. The primary criteria for the selection of maintenance protective coatings used within the Containment building are:

1. Capability of being easily decontaminated

2. Capability of not reacting chemically with spray solutions

3. Capability of preventing the formation of gaseous or solid waste products

4. Capability of resisting the environmental radiation for the life of the plant

5. Capability of withstanding D.B.A. conditions individually tested as described above in accordance with ASTM D 3911-03 [Ref. 9]

The surveillance program for testing, inspection of documentation of the Service Level I protective coating systems inside the Containment buildings includes:

A - Qualification and training of inspection personnel.

B - Inspection and testing procedures which specify:

1. Operational methods for each inspection and test;
2. Inspection equipment;
3. Frequency of testing and inspection;
4. Acceptance criteria for each inspection and test; and
5. Record keeping to document inspections and tests.

C - Verification of storage and handling of protective coatings.

D - Calibration of measuring and test equipment.

E - Reporting, disposition, and tracking of coating degradation and deficiencies

F - Completion, issuance, and control of documentation.

G - Maintenance and Control of the Coatings Exempt Log.

Charcoal and oil present inside the containment are located within filter housings and mechanical components respectively. Thus, charcoal and oil will not be exposed to the containment spray and will not create debris or methane.

6.1B.3 POSTACCIDENT CHEMISTRY

In the event of an accident, sodium hydroxide and boric acid solutions are present in the Containment sump. Parameter ranges used for calculation of equilibrium sump solution pH following an accident are given in Table 6.5-3. For sources of boron in the sump following an accident, see Table 6.1B-4. The range of equilibrium sump solution pH provided by the Containment Spray System (CSS) and its chemical additive subsystem is described in Section 6.5.2.

Adequate mixing of these solutions is assured by draining all major volumes in the Containment to the Containment sump. The only volume potentially capable of retaining a significant volume of spray solution, thereby preventing mixing of that volume, is the reactor cavity. The solution held up in the reactor cavity has a pH equal to that of the spray solution during injection, and loss of this volume is considered in calculating the minimum Containment sump pH.

Since the pH range of the Containment sump solution is relatively high, corrosion of aluminum components is limited by restricting the use of aluminum inside Containment as discussed in Section 6.2.5.

REFERENCES

1. 10 CFR Part 50, Appendix A, GDC 1, Quality Standards and Records.

2. 10 CFR Part 50, Appendix A, GDC 38, Containment Heat Removal.

3. 10 CFR Part 50, Appendix A, GDC 41, Containment Atmosphere Cleanup.

4. NRC Regulatory Guide 1.31, Control of Stainless Steel Welding, Revision 1, June 1973, U. S. Nuclear Regulatory Commission.

4a. NRC Regulatory Guide 1.31, Control of Ferrite Content in Stainless Steel Weld Metal, Revision 2, May 1977, U.S. Nuclear Regulatory Commission.

5. NRC Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel, February 1973, U.S. Nuclear Regulatory Commission.

6. NRC Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel, May 1973, U.S. Nuclear Regulatory Commission.

7. EPRI Report 1003102, “Guideline on Nuclear Safety-Related Coatings”, Revision 1 (formerly TR-109937).

8. ASTM D 5144-00, Standard Guide for Use of Protective Coating Standards in Nuclear Power Plants.

9. ASTM D 3911-03, Standard Test Method for Evaluating Coatings Used in Light-Water Nuclear Power Plants at Simulated Design Basis Accident (DBA) Conditions.

10. ASTN A-262-70 Practice E, Copper-Copper Sulfate-Sulfuric Test for Detecting Susceptibility to Intergranular Attack in Stainless Steels, Annual Book of ASTM Standards, Part 3, American Society for Testing and Materials.

11. ASTM A-380, Recommended Practice for Cleaning and Descaling Stainless Steel Parts, Equipment and Systems.

12. Branch Technical Position MTEB 6-1, pH for Emergency Coolant Water, appended to Standard Review Plan 6.1.1.

13. STM C692-71, Evaluating Stress Corrosion Effect of Wicking-Type Thermal Insulations on Stainless Steel.

14. RDT M12-IT, Text Requirements for Thermal Insulating Materials for Use on Austenitic Stainless Steel, Section 5, Knolls Atomic Power Laboratory.

15. American Society for Metals Handbook, Vol. 6, pp. 246-471.

16. AWS A4.2-74, Standard Procedures for Calibration Magnetic Instruments to Measure the Delta Ferrite Content of Austenitic Stainless Steel Weld Metal.

17. ER-ME-124, Evaluation of CPSES Protective Coatings, Revision 0, November 28, 2007.

18. Deleted.

19. Model Testing of the Recirculation Containment Sump, Comanche Peak Units 1 and 2, Western Canada Hydraulic Labratories, November 1981.

TABLE 6.1B-1
ESF COMPONENT MATERIALS SPECIFICATIONS

(Sheet 1 of 2)

Component	Material
1. Containment Spray System	
Heat Exchanger	
Shell	SA-516 Gr. 70
Bonnet	SA-240 TP 304
Tube Support	SA-285 Gr. C FBQ
Baffles	SA-285 Gr. C FBQ
Tubes	SA-249 TP 304
Tubesheets	SA-240 TP 304
Gaskets	Flexi Carb
Nozzles (shell)	SA-106 Gr. B
Nozzles (bonnet)	SA-358 Class I TP 304 or 316
Couplings	SA-182 F 304 or 316
Pump	
Casing	SA-351 CF8M
Impeller	SA-351 CF8M or CF3M
Shaft	SA-182 Gr. 316 L
Shaft Sleeves	SA-182 Gr. 316 L
Radial sleeve bearings	A-48 CL30
Ball thrust bearings	A-295
Mechanical seal	SA-182 F 304/316
Coupling	Forged Alloy Steel
Gasket	Permanite XJ534 or SF3500
Chemical Additive Tank	
Shell	SA-240 TP 304
Heads	SA-240 TP 304
Nozzles	SA-312 TP 304
Flanges	SA-182 TP 304
Refueling Water Storage Tank	
Liner	SA-240 TP 304

TABLE 6.1B-1
ESF COMPONENT MATERIALS SPECIFICATIONS

(Sheet 2 of 2)

Component	Material
Spray Nozzles	SA-351 Gr. CF8 TP 304
Chemical Eductor	
Body	SA-182 Gr. F 304
Motive Nozzle	SA-182 Gr. F 304
Motive Flange	SA-240 TP 304
Suction Nozzle	SA-312 TP 304
Suction Flange	SA-182 Gr. F 304
Discharge Nozzle	SA-182 Gr. F 304
Discharge Flange	SA-182 Gr. F 304
Recirculation Sump Screens	SA-249 TP 316
Piping	SA 312 and SA 358 CL1 TP 304 or TP 316

TABLE 6.1B-2
ESF VALVE MATERIALS SPECIFICATIONS

Pressure Retaining Components

Part	Material
Bodies	SA-351 Grade CF8 or Grade CF8M SA-182 Grade F 316 SA-105 SA-216 Grade WCB or WCC SA-515 Grade 70
Bonnets	SA-351 Grade CF8 or Grade CF8M SA-182 Grade F 316 SA-479 Type 316 SA-182 Grade F 11 SA-105 SA-217 Grade WC6 SA-350 Grade LF1 or LF2
Discs[a]	SA-182 Grade F 316 SA-351 Grade CF8M with N: Plating SA-479 Type 416 or Type 316 SA-182 Grade F11 A-567 Grade 1 (Stellite 21)
Closure Bolting and Nuts	SA-453 Grade 660 SA-193 Grade B6 or Grade B7 SA-564 Grade 630 SA-194 Grade 2H SA-194 Grade 8M

a) Diaphragm material for Saunders type valves is EPT Grade M

TABLE 6.1B-3
ORGANIC MATERIALS USED INSIDE CONTAINMENT

Material		Quantity (Per Unit)
Charcoal (filters)		11,544 lb
Plastic (cable insulation and jacket)		approximately 60,200 lb
Coatings	Steel:	333,000 sq. ft.
	Concrete:	285,000 sq. ft.
Oil		approximately 1435 gal.

TABLE 6.1B-4
SOURCES OF BORON IN SUMP FOLLOWING A LOCA

Source	Borated Water (gal)	Boron Concentration (ppm)
RWST	388,677 to 481,919	2400 to 2600
Accumulators	24,476 to 26,388	2300 to 2600
RCS	88,232.7	0 to 1850

6.2 CONTAINMENT SYSTEMS

6.2.1 CONTAINMENT FUNCTION DESIGN

6.2.1.1 Containment Structure

6.2.1.1.1 Design Bases

The Containment Building (Reactor Building) design meets the requirements of General Design Criteria (GDC) 16 and 50 and is in accordance with the following:

1. Postulated LOCAs and secondary system breaks are considered in combination with loss of offsite power and single active failures in determining the maximum pressure and temperature.

2. The Containment Building and associated systems are designed such that the calculated Containment pressure following a LOCA or a secondary system break is below the design pressure.

3. The sources and amounts of mass and energy released to the Containment are conservatively determined as discussed in Subsections 6.2.1.3 and 6.2.1.4.

4. The Containment pressure is reduced to less than 50 percent of the Containment design pressure within 24 hr after the postulated accident. This is consistent with the assumptions used in the offsite dose analyses presented in Chapter 15.

5. The minimum calculated Containment pressure is not less than the pressure used in the analysis of the ECCS performance capability.

   The minimum Containment pressure analysis is discussed in Subsection 6.2.1.5.

6. The maximum calculated external pressure differential resulting from inadvertent actuation of the Containment Spray System (CSS) is below the Containment external design pressure.

7. The Containment internal structures are designed to withstand the differential pressure loadings resulting from pipe breaks within the Containment subcompartments. The details are presented in Subsection 6.2.1.2.

8. Instrumentation capable of operating in the postaccident environment is provided to monitor the Containment pressure and temperature and the sump water level after an accident. The details of the instrumentation provided are given in Section 7.5.

6.2.1.1.2 Design Features

The Containment consists of a steel-lined, reinforced concrete structure which houses the nuclear steam supply system (NSSS) and certain portions of the ESF systems. The general arrangement drawings are included in Section 1.2.

The Containment is designed to limit the leakage of radioactive fission products to the environment in the event of an accident inside the Containment. The structural design of the Containment is presented in Section 3.8.1. The design provisions to protect the Containment structure and the ESF systems from pipe whip and missiles resulting from postulated accidents are discussed in Sections 3.5 and 3.6. Applicable codes and standards are listed in Section 3.8. The Containment Ventilation System is discussed in Section 9.4.

The principal design parameters of the Containment are listed in Table 6.2.1-1.

6.2.1.1.3 Design Evaluation

6.2.1.1.3.1 Spectrum Of Breaks Analyzed

1. LOCA

   The Containment pressure temperature transient response is analyzed for a large area rupture of the RCS at two distinct locations:

   a. Hot leg (between reactor vessel and steam generator)

   b. Pump suction (between steam generator and reactor coolant pump)

   The specific breaks analyzed are

   a. Double-ended pump suction guillotine (DEPSG)

   b. Double-ended hot leg guillotine (DEHLG)

   The DEPSG break is analyzed assuming minimum ECCS operation (minimum ESF) and assuming maximum ECCS operation (one out of two Containment Spray trains operating - Minimum Containment Spray System Operation). The DEHLG is only analyzed through blowdown, so ECCS operation is not applicable.

   The use of identical mass and energy release data (Reference 17) Component Cooling Water (CCW) system flow rates (affecting the Residual Heat Removal (RHR) and the CSS heat exchanger), the CSS actuation delay time, and containment spray header fill time in the analysis of postulated LOCAs for both Units 1 and 2 results in identical containment pressure and temperature responses to the postulated scenarios. Section 6.2.1 refers to Tables and Figures that represent both Units 1 and 2 analysis results.

2. Steam Line Breaks

   The Containment response is presented for a spectrum of main steam line breaks. Four power levels (100.6 percent, 70 percent and 30 percent of 3628 MWt, and hot shutdown) are considered. A full double-ended rupture and a split rupture are presented at each power level.

6.2.1.1.3.2 Results

The calculated peak pressures and temperatures resulting from postulated LOCAs and steam line breaks for Unit 1 are summarized in Tables 6.2.1-2 and 6.2.1-2A, respectively.

The pressure margins and percent pressure margins are also listed.

Conservative values of the initial steam generator water and steam inventories are used.

The results of the Containment pressure temperature analysis (limiting cases) for MSLB are graphically presented in Figures 6.2.1-3 and 6.2.1-4.

Among the steam line breaks analyzed, for Units 1 and 2 the 4.3 ft^2 split rupture at 100.6% power results in the maximum containment temperature while the 4.7 ft^2 split rupture at 30% power results in the maximum containment pressure, respectively.

The containment pressure and temperature analysis for LOCA used for the environmental qualification evaluations are based on a GOTHIC run of the DEPS MINSI case which recalculated refueling water storage tanks (RWST) draindown times and reflected an increased component cooling water (CCW) flow after the sump temperature falls below 200 degrees F.

The temperature and pressure profiles utilized for EQ evaluations as described in section 3.11B bounds the limiting temperature and pressure transients for postulated LOCA and MSLB events.

6.2.1.1.3.3 Method Of Analysis

The Containment pressure and temperature responses due to a spectrum of the LOCAs and main steam line break accidents are analyzed using the computer program, GOTHIC.

The analytical model for the GOTHIC program is described in Section 6.2.1.1.3.11.

6.2.1.1.3.4 Mass And Energy Data

Mass and energy release analysis for the LOCA is presented in Subsection 6.2.1.3. Energy inventories, mass and energy balances, and release data for the spectrum of breaks analyzed are also included in Subsection 6.2.1.3.

The generic mass and energy release analysis for the steam line breaks is described in Reference [6]. A discussion of the mass and energy releases for the Comanche Peak Nuclear Power Plant (CPNPP) is included in Subsection 6.2.1.4.

6.2.1.1.3.5 Containment Initial Conditions

The initial Containment pressure and temperature, used in the analysis are shown in Table 6.2.1-5. Table 6.2.1-5 also lists the temperatures of the refueling water, component cooling water and service water.

6.2.1.1.3.6 Failure Mode Analysis

1. LOCA

   The DEPSG breaks are analyzed assuming minimum effectiveness of the CSS, i.e., only one out of two spray trains is operating. A single failure analysis of the CSS is included in Subsection 6.2.2.

   Both maximum and minimum ECCS operation is considered in the analysis of the design basis LOCA: the DEPSG break.

2. Steam Line Breaks

   The following safety system failures are considered in the analysis of steam line breaks:

   a. Failure of the feedwater line isolation valve to close

   b. Failure of steam line stop valve

   c. Failure of one Containment spray train

A discussion of the failures considered is given in Subsection 6.2.1.4.

6.2.1.1.3.7 Structural Heat Sinks

The passive structural heat sinks assumed in the analysis are tabulated in Table 6.2.1-6.

An interface thermal conductivity of 0.0161 Btu/hr-ft-F, and volumetric heat capacity of 0.0167 Btu/ft^3-F is used between the steel liner and the concrete for the dome an cylindrical portion of the containment wall.

All heat sinks in Containment are assumed to be painted. Paint thermal conductivities of 0.0875 and 0.0700 Bth/hr-ft-F are used for steel and concrete surfaces, respectively. Also, a paint volumetric heat capacity of 0.1 Btu/ft^3-F is assumed for both steel and concrete structures. The contact between paint layers and heat sink outer surfaces is considered to be adhesive, and accordingly, thermal contact resistance is taken as zero.

The thermophysical properties of the heat sink materials are tabulated in Table 6.2.1-8.

The heat absorption calculations are based on the Diffusion Layer Model (DLM) heat transfer coefficient for the LOCA and for the MSLB analyses.

6.2.1.1.3.8 Accident Chronology

For the design basis LOCA, the significant events and their times of occurrence are shown in Table 6.2.1-9. For the design basis steam line break, the chronology of major events is presented in Table 6.2.1-10.

6.2.1.1.3.9 External Pressure Analysis

The Containment is designed for an external differential pressure of five psi (See Section 3.8.1.3), which is well above the maximum differential pressure resulting from inadvertent operation of the CSS.

The differential pressure resulting from inadvertent CSS actuation is calculated using the following assumptions:

1. The initial containment pressure is assumed to be 14.2 psia.

2. The containment temperature is assumed to be reduced from an initial value of 120°F to the minimum expected containment spray (refueling water) temperature of 40°F.

3. The relative humidity is assumed to be 100 percent.

With the previously mentioned assumptions, the maximum external pressure differential is calculated to be 3.79 psi. This value is below the design value of five psid.

The Containment is capable of withstanding the design external pressure differential; therefore, no special provision or operator action is required to protect the Containment against inadvertent spray actuation.

6.2.1.1.3.10 Boron Injection Tank Removal Analysis

The main steamline ruptures were analyzed based on the removal of the Boron Injection Tank (BIT). See Section 6.2.1.1.3.2 for results.

6.2.1.1.3.11 GOTHIC Computer Program and Containment Analysis Analytical Model

Calculation of the containment response following a postulated LOCA was analyzed by use of the digital computer code GOTHIC. GOTHIC version 7.2a was used for the LOCA containment response analysis. The GOTHIS Technical Manual (Reference 18) provides a description of the governing equations, constitutive models, and solution methods in the solver. The GOTHIC Qualifications Report (Reference 19) provides a comparison of the solver results with both analytical solutions and experimental data.

The GOTHIC containment modeling for CPNPP is consistent with the recent NRC approved Ginna evaluation model (Reference 20). The latest code version is used to take advantage of the diffusion layer model (DLM) heat transfer option. This heat transfer option was approved by the NRC (Reference 20) for use in Ginna containment analyses with the condition that mist be excluded from what was earlier termed as the mist diffusion layer model (MDLM). The GOTHIC containment modeling for CPNPP has followed the conditions of acceptance placed on Ginna. Ginna and CPNPP both have large dry containment designs. The CPNPP containment volume is considerably larger because CPNPP is a 4-loop plant and Ginna is a 2-loop plant. The only other notable difference is that CPNPP has two independent and redundant containment spray systems whereas Ginna has one spray system and service water cooled fan coolers. None of the user-controlled enhancements added to version 7.2a were implemented in the CPNPP containment model.

The containment response for design basis LOCA and steam line break containment integrity is an American Nuclear Society (ANS) Condition IV event, an infrequent fault. The relevant requirements to satisfy NRC acceptance criteria are as follows:

1. GDC-16 and -50: In order to satisfy the requirement of GDC-16 and -50, the peak calculated containment pressure should be less than the containment design pressure of 50 psig.

2. GDC-38: In order to satisfy the requirement of GDC-38, the calculated pressure at 24 hours should be less than 50 percent of the peak calculated value. (This is related to the criteria for containment leakage assumptions as affecting doses at 24 hours.)

6.2.1.2 Containment Subcompartments

6.2.1.2.1 Design Bases

The Containment Building subcompartments are the fully or partially enclosed volumes within the Containment which contain high energy lines. These subcompartments are designed to limit the adverse effects of a postulated high energy pipe rupture within them. Subcompartment multi-node pressurization analyses have been performed to investigate the consequences of such high energy line ruptures and to ensure the adequacy of the subcompartment design, both with respect to the integrity of the structure itself and with respect to possible asymmetric pressure loads on safety related components situated within the affected subcompartments. All postulated pipe break locations and types for the analysis were chosen in accordance with NRC Regulatory Guide 1.46 in order to select a design basis rupture yielding the highest mass and energy release rates consistent with break location criteria. However, in accordance with the 1987 revision to GDC-4 (Refer to Section 3.6B.2), the dynamic effects of RCS main loop piping breaks and RCS branch line breaks 10 inch diameter and larger have been eliminated from consideration. Specifically, subcompartment pressurization analyses were performed for the following subcompartments and design basis pipe ruptures:

1. Postulated Pipe Break Types and Locations

   a. Steam Generator Compartment

      The following breaks are used in evaluating both the compartment pressurization and the RCS component asymmetric pressurization:

      1. Main steam line full guillotine break in steam generator compartment No. 3.

      2. Main steam line full guillotine break in steam generator compartment No. 4.

      3. Feedwater line full guillotine break in steam generator compartment No. 4.

      4. Residual heat removal 6" line full guillotine break in steam generator compartment No. 4.

5. Auxiliary feedwater 6" line full guillotine break in steam generator compartment No. 4.

Note: Except for the main steam line break in steam generator compartment No. 3, the results obtained from steam generator compartment No. 4 are representative of the other compartments.

b. Main Steam Penetration Area

A full guillotine break was assumed. This break determined compartment structural loads only as no components were subjected to differential pressure loading.

c. Feed Water Penetration Area

A full guillotine break was assumed. This break determined compartment structural loads only, as no components were subjected to differential pressure loading.

d. Pressurizer Compartment

A full guillotine spray line break at the nozzle was assumed for evaluating both the compartment structural design and the component supports design.

6.2.1.2.2 Design Features

Figures 1.2-8 and 1.2-11 through 1.2-21 provide detailed plant and evaluation drawings of the containment subcompartments. The internal structures and equipment locations are shown on these drawings. The volume and vent areas for each subcompartment are discussed in Section 6.2.1.2.3.

6.2.1.2.3 Design Evaluation

Containment subcompartment analyses are performed to calculate the differential pressure transient across major equipment and walls that will result from postulated pipe ruptures. The resulting pressure gradients are used to evaluate the loads and moments on major equipment supports. The differential pressures across the subcompartment walls are used as the design basis for the structures. Section 3.8.3 provides the acceptance criteria for the structures.

A model is developed for each subcompartment to predict a conservative pressure response. Each subcompartment is subdivided into a network of control volumes or nodes. Boundaries between control volumes, which represent junctions or vent paths, are located at physical discontinuities where geometric influences are expected to create a pressure differential. A detailed description of each subcompartment model is given later in this section.

The assumed initial conditions for the subcompartment volumes are conservatively chosen to maximize the resultant differential pressure responses. The values selected are as follows:

Maximum temperature (°F)	120.0
Minimum air partial pressure (psia)	14.2
Minimum relative humidity (%)	0.1

The containment subcompartment pressurization analyses are performed with the RELAP4/MOD5 computer program [Reference 16]. The critical flow correlation selected for each vent path is the homogeneous equilibrium model (HEM).

The vent loss coefficient depends on the geometry of the particular vent. The values of the total loss coefficients for both forward and reverse flow directions are simply the sum of the loss coefficients for each portion of the vent path. These total loss coefficients consist of the following; contraction and expansion losses which are determined as a function of the ratio of the upstream and/or downstream cross-sectional area to the cross-sectional area of the vent, form losses which are due to objects in the flow path such as grating. Sensitivity analyses to evaluate the effects of additional steel grating in the steam generator loop rooms as well as in the pressurizer compartments were performed using RELAP4/MOD5 computer program.

Mass and energy release rate data for the pressurizer spray line break are calculated by Westinghouse, as described in Reference [17], using the SATAN-V computer code. A 10 percent safety margin is applied to the release rates for Unit 1 (covers the 9 percent penalty associated with the replacement steam generator program and 4.5% uprate), while a one percent safety margin is applied to the release rates for Unit 2. The methods used by SATAN-V short-term mass and energy release analyses for evaluation of critical flow were reviewed. The results indicated that critical flow through an orifice is higher than critical flow through a pipe, and that SATAN-V, in terms of pressure, break flow and break energy, yields conservative results.

The SATAN-V critical flow calculation is dependent upon the fluid conditions at the break location. For subcooled fluid conditions, a modification of the Zaloudek correlation is applied with a discharge coefficient of 1.0. The parameters which determine subcooled critical flow are the reservoir pressure and the saturation pressure corresponding to reservoir conditions. The Moody correlation, a thermodynamic equilibrium critical flow model also with a discharge coefficient of 1.0, is used for saturated and two-phase fluid conditions. The Moody model is a function of stagnation properties. (See Reference [9] for more detailed description of these break flow models.)

These critical flow models were compared to the subcooled and saturated data presented in Reference [10]. Reference [10] contains representative data for nozzles of varying entrance geometry, length and diameter. In the two-phase region, the Moody model underpredicted some of the applicable data. By applying a multiplier to the SATAN-V correlation, the data fell beneath the curve generated from this modified correlation. Similarly, the Zaloudek model was non-conservative when compared to several subcooled data points. A multiplier on the Zaloudek equation provided a correlation which represented an upper bound to the data.

In order to determine the effect of these modified correlations, the adjusted critical flow model was programmed into the SATAN-V code for all break locations analyzed. Results indicate that for all break locations, with the exception of the reactor cavity hot leg break, the analyses

performed using the adjusted critical flow models compare favorably to the analyses which used the unmodified correlations. The largest variation in break flows was less than 1%. For the reactor cavity hot leg break, the effect of the multiplier on break flow becomes somewhat more pronounced, and the resulting peak release rate increased by approximately 3.5%. Due to the fact that this break is not the most limiting for a reactor cavity break, these results do not justify any change in the data used for subcompartment analyses nor do they require reanalysis of subcompartment pressures. The trend in the mass release transient is reflected in the resulting differential pressure transient; thus, the peak differential pressure will be determined by the dominant reactor cavity break in terms of break flow (the cold leg break). Since a 40% margin was applied to the calculated pressure differentials, the results currently reported are sufficiently conservative under review of the current critical flow data. Of this 40%, 10% is directly attributable to calculated mass and energy releases. Only 1% of the 10% margin on the short-term pressurizer spray line break mass and energy releases remains because 9% of the margin was needed to cover the effects of the replacement steam generator and 4.5% uprate program.

The mass and energy release rates for the main steam, feedwater, and auxiliary feedwater line breaks were calculated based on Westinghouse Safety Analysis Standard 12-1 [Reference 15]. The mass and energy release rates for the residual heat removal line break were developed using the Zaloudek correlation, as developed in Westinghouse report WCAP-8312-A [Reference 7].

The peak loads on the steam generators, reactor coolant pumps, and the pressurizer due to asymmetric pressurization of the surrounding cubicle are provided in Table 6.2.1-94 for each of the postulated pipe ruptures evaluated. The cubicle number and postulated rupture producing the loads are also specified.

These loads are resolved about the steam generator at the elevation of the upper support, the reactor coolant pump at the elevation of the pump feet, and the pressurizer at the elevation of the upper support.

Descriptions of the subcompartment geometric models and results are presented below:

STEAM GENERATOR COMPARTMENTS

The steam generator compartment analysis employs two nodalization models due to geometry differences between compartments. They are steam generator compartment No. 3 model and steam generator compartment No. 4 model which also represents Steam Generator No. 1 and No. 2. Both models employ fine vertical and horizontal subdivisions to maximize the local peak pressure for various breaks. All major flow area changes are included in the models. Thus, no further sensitivity study is performed.

This analysis assumes flow through the various gratings located in the steam generator compartments. Grating blockage caused by insulation debris is considered negligible. Other major vent paths exist which are free of grating. In addition, grating free area (80%) is conservatively input as sixty percent of total grating area.

Conservative design for regions removed from a particular break location is assured by evaluating potential break locations closer to these regions.

The effects of the additional sludge lancing platforms in the steam generator compartment were evaluated. The addition of this grating affects the flow areas and resistance coefficients. The effects of the additional steel grating were determined to be negligible; thus, the original analysis remains valid.

MAIN STEAM AND FEEDWATER PENETRATION AREAS

Nodal boundaries are chosen at the most restrictive locations in order to maximize local peak pressure. A nodalization sensitivity study was not performed, since the node flow areas are very large in comparison to the areas available at the nodal boundaries.

Conservative design is assured for regions removed from a particular break location by considering additional break locations in these downstream volumes.

There are no safety-related components subjected to asymmetric pressurization in the containment penetration area. Maximum wall differential pressures are given in Table 6.2.1-92.

There are no safety-related components subjected to asymmetric pressurization in the containment penetration area. Maximum wall differential pressures are given in Table 6.2.1-78.

The analysis of the pressure versus time provides the basis for design evaluation of these structures.

PRESSURIZER COMPARTMENT

Node boundaries are chosen at the most restrictive flow areas to maximize local peak pressures. The pressurizer compartment spray line break analysis considers all vertical and horizontal flow obstacles.

The effects of the additional steel grating in the pressurizer compartment were analyzed. The effects of the additional steel grating were determined to be negligible; thus, the results of the original RELAP-4 analysis remain valid.

6.2.1.3 Mass and Energy Release Analyses for Postulated Loss-of-Coolant Accidents

The M&E release rates described in this section form the basis of further computations to evaluate the containment following the postulated accident. Discussed in this section are the long-term LOCA M&E releases for the hypothetical double-ended pump suction (DEPS) rupture with minimum safeguards and maximum safeguards and double-ended hot-leg (DEHL) rupture break cases. These LOCA cases are used for the long-term containment integrity analyses in Section 6.2.1.1.3.2.

6.2.1.3.1 Input Parameters and Assumptions

The M&E release analysis is sensitive to the assumed characteristics of various plant systems, in addition to other key modeling assumptions. Where appropriate, bounding inputs are utilized and instrumentation uncertainties are included. For example, the RCS operating temperatures are chosen to bound the highest average coolant temperature range of all operating cases and a temperature uncertainty allowance of +5.9°F is then added. Nominal parameters are used in certain instances. For example, the RCS pressure in this analysis is based on a nominal value of

2,250 psia plus an uncertainty allowance +30.0 psi. All input parameters are chosen consistent with accepted analysis methodology.

Some of the most critical items are the RCS initial conditions, core decay heat, safety injection flow, and primary and secondary metal mass and steam generator (SO) heat release modeling. Specific assumptions concerning each of these items are discussed in the following paragraphs. Tables 6.2.1-56 and 6.2.1-57 present key data assumed in the analysis of CPNPP Units 1 and 2. Only one analysis is performed because Unit 1 with the model Δ76 steam generators bounds Unit 2 with the model D5 pre-heat steam generators.

The core rated power of 3,612 MWt plus the adjustment for the plant specific calorimetric error of 0.6 percent was used in the analysis. As previously noted, RCS operating temperatures were used to bound the highest average coolant temperature range as bounding analysis conditions. The use of higher temperatures is conservative because the initial fluid energy is based on coolant temperatures that are at the maximum levels attained in steady-state operation. Additionally, an allowance to account for instrument error and deadband is reflected in the initial RCS temperatures. The selection of 2,250 psia plus uncertainty as the limiting pressure is considered to affect the blowdown phase results only, since this represents the initial pressure of the RCS. The RCS rapidly depressurizes from this value until the point at which it equilibrates with containment pressure.

The rate at which the RCS blows down is initially more severe at the higher RCS pressure. Additionally, the RCS has a higher fluid density at the higher pressure (assuming a constant temperature) and subsequently has a higher RCS mass available for releases. Thus, 2,250 psia plus uncertainty was selected for the initial pressure as the limiting case for the long-term M&E release calculations.

The selection of the fuel design features for the long-term M&E release calculation is based on the need to conservatively maximize the energy stored in the fuel at the beginning of the postulated accident (that is, to maximize the core stored energy). The core stored energy that was selected to bound the 17x17 fuel product that will be used at CPNPP Units 1 and 2 was 3.75 full-power seconds (FPS). The margins in the core stored energy include a statistical uncertainty to address the thermal fuel model and associated manufacturing uncertainties and the time in the fuel cycle for maximum fuel densification. Thus, the analysis very conservatively accounts for the stored energy in the core.

Margin in RCS volume of 3 percent (which is composed of 1.6 percent allowance for thermal expansion and 1.4 percent allowance for uncertainty) was modeled.

A uniform steam generator tube plugging (SGTP) level of 0 percent was modeled. This assumption maximizes the reactor coolant volume and fluid release by virtue of consideration of the RCS fluid in all SG tubes. During the post-blowdown period, the SGs are active heat sources since significant energy remains in the secondary metal and secondary mass that has the potential to be transferred to the primary side. The 0 percent tube plugging assumption maximizes the heat transfer area and, therefore, the transfer of secondary heat across the SG tubes. Additionally, this assumption reduces the reactor coolant loop resistance, which reduces the pressure drop (i.e., ΔP) upstream of the break for the pump suction breaks and increases break flow. Thus, the analysis conservatively accounts for the level of SGTP.

The secondary-to-primary heat transfer is maximized by assuming conservative heat transfer coefficients. This conservative energy transfer is ensured by maximizing the initial internal energy of the inventory in the SG secondary side. This internal energy is based on full-power operation plus uncertainties.

Regarding safety injection (SI) flow, the M&E release calculation considered configurations/ failures to conservatively bound respective alignments. The cases include a minimum safeguards case that represents a failure of one diesel generator with one centrifugal charging pump (CCP), one SI pump, and one residual heat removal (RH) pump; and a maximum safeguards case with two CCPs, two SI pumps, and two RH pumps. In addition, the containment backpressure is assumed to be equal to the containment design pressure during the early portion of the transient. This assumption was shown in WCAP-I0325-P-A (Reference 17) to be conservative for the generation of M&E releases.

In summary, the following assumptions were employed to ensure that the M&E releases are conservatively calculated, thereby maximizing energy release to containment:

- Maximum expected operating temperature of the RCS (100 percent full-power conditions)
- Allowance for RCS temperature uncertainty (+5.9°F)
- Margin in RCS volume of 3 percent (which is composed of 1.6 percent allowance for thermal expansion and 1.4 percent allowance for uncertainty)
- Core rated power of 3,612 MWt
- Allowance for calorimetric error (+0.6 percent of power)
- Conservative heat transfer coefficients (that is, SG primary/secondary heat transfer, and RCS metal heat transfer)
- Allowance in core stored energy for effect of fuel densification
- A margin in core stored energy (statistical uncertainty to account for manufacturing tolerances)
- An allowance for RCS initial pressure uncertainty (+30.0 psi)
- A maximum containment backpressure equal to design pressure (50.0 psig)
- SGTP leveling (0 percent uniform)
    - Maximizes reactor coolant volume and fluid release
    - Maximizes heat transfer area across the SG tubes
    - Reduces coolant loop resistance, which reduces the ΔP upstream of the break for the pump suction breaks and increases break flow

- Main feedwater addition is modeled. The feedwater control valve closure time is based on the time to reach the SI signal, plus electronic delay and valve stroke time.

- The SG initial fluid mass was calculated at full (100 percent), accounting for level and methodology uncertainties.

Thus, based on the previously discussed conditions and assumptions, an analysis of CPNPP Units1 and 2 was made for the release of M&E from the RCS in the event of a LOCA at 3,612 MWt plus the plant specific power uncertainty of 0.6 percent.

6.2.1.3.1.1 Decay Heat Model

ANS Standard 5.1 (Reference 23) was used in the LOCA M&E release model for CPNPP Units 1 and 2 for the determination of decay heat energy. This standard was balloted by the Nuclear Power Plant Standards Committee (NUPPSCO) in October 1978 and subsequently approved. The official standard (Reference 23) was issued in August 1979. Table 6.2.1-49 lists the decay heat curve used in the CPNPP Units 1 and 2 SPU Program M&E release analysis.

Significant assumptions in the generation of the decay heat curve for use in the LOCA M&E releases analysis include the following:

1. The decay heat sources considered are fission product decay and heavy element decay of U-239 and Np-239.

2. The decay heat power from fissioning isotopes other than U-235 is assumed to be identical to that of U-235.

3. The fission rate is constant over the operating history of maximum power level.

4. The factor accounting for neutron capture in fission products is taken from Table 10 of the ANS Standard 5.1 (Reference 23).

5. The fuel is assumed to be at full power for 10^8 seconds.

6. The number of atoms of U-239 produced per second is assumed to be equal to 70 percent of the fission rate.

7. The total recoverable energy associated with one fission is assumed to be200 MeV/ fission.

8. An uncertainty of two sigma (two times the standard deviation) has been applied to the fission product decay.

Based upon NRC staff review (Safety Evaluation Report (SER) of the March 1979 evaluation model [Reference 17]), use of the ANS Standard-5.1, November 1979 decay heat model was approved for the calculation of M&E releases to the containment following a LOCA.

6.2.1.3.1.2 Application of Single-Failure Criterion

An analysis of the effects of the single-failure criterion has been performed on the M&E release rates for each break analyzed. An inherent assumption in the generation of the M&E release is that offsite power is lost. This results in the actuation of the emergency diesel generators (EDG's), required to power the Safety Injection System (SIS). Actuation of the EDG to provide power delays the star of operation of the SIS, that is essential to mitigate the transient. Since none of the powered safety systems were assumed to be operational during the blowdown phase, the application of single-failure criteria is not an issue for the blowdown period, which is limited by the DEHL break.

Two cases have been analyzed to assess the effects of a single failure. The first case assumes minimum safeguards SI flow based on the postulated single failure of one diesel generator. This results in the loss of one of each ECCS pump type and a loss of some containment heat removal systems. The second case assumes maximum safeguards SI flow based on no postulated failures that would impact the amount of ECCS flow. The failure for this second case would be taken as the loss of one train of containment spray pumps. The analysis of the cases described provides confidence that the effect of credible single failures is bounded.

6.2.1.3.2 Acceptance Criteria for Analyses

A large-break LOCA (LBLOCA) accident is classified as an American Nuclear Society (ANS) Condition IV event, an infrequent fault. To satisfy the NRC acceptance criteria presented in the Standard Review Plan, Section 6.2.1.3 (Reference 24), the relevant requirements are the following:

- 10 CPR 50, Appendix A
- 10 CPR 50, Appendix K, paragraph I.A

To meet these requirements, the following must be addressed:

- Sources of energy
- Break size and location
- Calculation of each phase of the accident
- M&E release data

The bounding M&E releases and related analysis information for CPNPP Units 1 and 2 are presented in Section 6.2.1.3.4. The containment response is provided in Section 6.2.1.1.

6.2.1.3.3 Description of Analyses

The evaluation model used for the long-term LOCA M&E release calculations is the March 1979 model described in WCAP-10325-P-A (Reference 17). The NRC review and approval letters for the evaluation model can be found in References 17, 25, and 27.

This report section presents the limiting long-term LOCA M&E releases generated in support of the CPNPP Units 1 and 2 SPU Program. These M&E releases are then used in the containment integrity analysis presented in Section 6.2.1.1.

6.2.1.3.3.1 LOCA Mass and Energy Release Phases

The containment system receives M&E releases following a postulated rupture in the RCS. These releases continue over a time period, which, for the LOCA M&E analysis, is typically divided into four phases.

Blowdown - the period of time from accident initiation (when the reactor is at steady-state operation) to the time that the RCS and containment reach an equilibrium state.

Refill - the period of time when the lower plenum is being filled by accumulator and Emergency Core Cooling System (BCCS) water. At the end of blowdown, a large amount of water remains in the cold legs, downcomer, and lower plenum. To conservatively consider the refill period for containment M&E releases, it is assumed that this water is instantaneously transferred to the lower plenum along with sufficient accumulator water to completely fill the lower plenum. This allows an uninterrupted release of M&E to containment. Thus, the refill period is conservatively neglected in the M&E release calculation.

Reflood - begins when the water from the lower plenum enters the core and ends when the core is completely quenched.

Post-reflood (FROTH) - describes the period following the reflood phase. For the pump suction break, a two-phase mixture exits the core, passes through the hot legs, and is superheated in the SGs prior to exiting the break as steam. After the broken-loop SG cools, the break flow becomes two phase.

6.2.1.3.3.2 Computer Codes

The WCAP-10325-P-A (Reference 17) M&E release evaluation model comprises M&E release versions of the following codes: SATAN VI, WREFLOOD, FROTH, and EPITOME. These codes were used to calculate the long-term LOCA M&E releases for the CPNPP Units 1 and 2 SPU Program.

SATAN VI calculates blowdown, the first portion of the thermal-hydraulic transient following break initiation, including pressure, enthalpy, density, M&E flow rates, and energy transfer between primary and secondary systems as a function of time.

The WREFLOOD code addresses the portion of the LOCA transient when the core reflooding phase occurs after the primary coolant system has depressurized (blowdown) due to the loss of water through the break and when water supplied by the ECCS refills the reactor vessel and provides cooling to the core. The most important feature of WREFLOOD is the steam/water mixing model (see subsection 6.2.1.3.4.2).

FROTH models the post-reflood portion of the transient. The FROTH code is used for the SG heat addition calculation from the broken and intact-loop SGs.

EPITOME continues the FROTH post-reflood portion of the transient from the time at which the secondary equilibrates to containment design pressure to the end of the transient. It also compiles a summary of data on the entire transient, including formal instantaneous M&E release tables and M&E balance tables with data at critical times.

6.2.1.3.3.3 Break Size and Location

Generic studies (Reference 17) have been performed with respect to the effect of postulated break size on the LOCA M&E releases. The double-ended guillotine break has been found to be limiting due to larger mass flow rates during the blowdown phase of the transient. During the reflood and FROTH phases, the break size has little effect on the releases.

Three distinct locations in the RCS loop can be postulated for a pipe rupture for M&E release purposes:

- Hot leg (between vessel and SG)
- Cold leg (between pump and vessel)
- Pump suction (between SG and pump)

The break locations analyzed for this program are the double-ended pump suction (DEPS) rupture with a total break area of 10.48 ft^2 and the double-ended hot leg (DEHL) rupture with a total break area of 9.17 ft^2. Break M&E releases have been calculated for the blowdown, reflood, and post-reflood phases of the LOCA for the DEPS cases. For the DEHL case, the releases were calculated only for the blowdown. The following information provides a discussion on each break location.

The DEHL rupture has been shown in previous studies to result in the highest blowdown M&E release rates. Although the core flooding rate would be the highest for this break location, the amount of energy released from the SG secondary is minimal because the bulk of the fluid that exits the core vents directly to containment, bypassing the SGs. As a result, the reflood M&E releases are reduced significantly as compared to either the pump suction or cold leg break locations where the core-exit mixture must pass through the SGs before venting through the break. For the hot leg break, generic studies (Reference 17) have confirmed that there is no reflood peak that is, from the end of the blowdown period, the containment pressure would continually decrease. Therefore, only the M&E releases for the hot leg break blowdown phase are calculated and presented in this section of the report.

The cold leg break location has also been found in previous studies to be much less limiting in terms of the overall containment energy releases. The cold leg blowdown is faster than that of the pump suction break, and more mass is released into the containment. However, the core heat transfer is greatly reduced, and this results in a considerably lower energy release into containment. Studies (Reference 17) have determined that the blowdown transient for the cold leg is, in general, less limiting than that for the pump suction break. During reflood, the flooding rate is greatly reduced and the energy release rate into the containment is reduced. Therefore, the cold leg break is bounded by other breaks and no further evaluation is necessary.

The pump suction break combines the effects of the relatively high core flooding rate, as in the hot leg break, and the addition of the stored energy in the SGs. As a result, the pump suction break yields the highest energy flow rates during the post-blowdown period by including all the available RCS energy in calculating the releases to containment. Thus, only the DEHL and DEPS cases are used to analyze long-term LOCA containment integrity.

6.2.1.3.4 Mass and Energy Release Data

6.2.1.3.4.1 Blowdown Mass and Energy Release Data

The SATAN-VI code is used for computing the blowdown transient. The code utilizes the control volume (element) approach with the capability for modeling a large variety of thermal fluid system configurations. The fluid properties are considered uniform and thermodynamic equilibrium is assumed in each element. A point-kinetics model is used with weighted feedback effects. The major feedback effects include moderator density, moderator temperature, and Doppler broadening. A critical flow calculation for subcooled (modified Zaloudek), two-phase (Moody), or superheated break flow is incorporated into the analysis. The methodology for the use of this model is described in WCAP-10325-P-A (Reference 17).

Table 6.2.1-39 presents the calculated M&E release for the blowdown phase of the DEHL break for CPNPP Units 1 and 2. For the hot leg break M&E release tables, break path 1 refers to the M&E exiting from the reactor vessel side of the break. Break path 2 refers to the M&E exiting from the SG side of the break. Table 6.2.1-54 present the M&E balance data for the Units 1 and 2 DEHL case.

Table 6.2.1-3 presents the calculated M&E releases for the blowdown phase of the DEPS breaks. For the pump suction breaks, break path 1 in the M&E release tables refers to the M&E exiting from the SG side of the break. Break path 2 refers to the M&E exiting from the pump side of the break.

6.2.1.3.4.2 Reflood Mass and Energy Release Data

The WREFLOOD code is used for computing the reflood transient. The WREFLOOD code consists of two basic hydraulic models: one for the contents of the reactor vessel and one for the coolant loops. The two models are coupled through the interchange of the boundary conditions applied at the vessel outlet nozzles and at the top of the downcomer. Additional transient phenomena such as pumped SI and accumulators, reactor coolant pump (RCP) performance, and SG releases are included as auxiliary equations that interact with the basic models as required. The WRFLOOD code permits the capability to calculate variations during the core reflooding transient of basic parameters such as core flooding rate, core and downcomer water levels, fluid thermodynamic conditions (pressure, enthalpy, density) throughout the primary system, and mass flow rates through the primary system. The code permits hydraulic modeling of the two flow paths available for discharging steam and entrained water from the core to the break, that is, the path through the broken loop and the path through the unbroken loops.

A complete thermal equilibrium mixing condition for the steam and ECCS injection water during the reflood phase has been assumed for each loop receiving ECCS water. This is consistent with the usage and application of the WCAP-10325-P-A (Reference 17) M&E release evaluation model in recent analyses, for example, D.C. Cook Docket (Reference 25). Even though the WCAP-10325-P-A (Reference 17) model credits steam/water mixing only in the intact loop and

not in the broken loop, the justification, applicability, and NRC approval for using the mixing model in the broken loop has been documented (Reference 25). Moreover, this assumption is supported by test data and is further discussed below.

The model assumes a complete mixing condition (that is, thermal equilibrium) for the steam/water interaction. The complete mixing process, however, is made up of two distinct physical processes. The first is a two-phase interaction with condensation of steam by cold ECCS water. The second is a single-phase mixing of condensate and ECCS water. Since the steam release is the most important influence to the containment pressure transient, the steam condensation part of the mixing process is the only part that must be considered. (Any spillage directly heats only the sump.)

The most applicable steam/water mixing test data have been reviewed for validation of the containment integrity reflood steam/water mixing model. This data was generated in 1/3-scale tests (Reference 26), which are the largest scale data available and thus most clearly simulate the flow regimes and gravitational effects that would occur in a pressurized water reactor (PWR). These tests were designed specifically to study the steam/water interaction for PWR reflood conditions.

A group of 1/3-scale tests discussed in Reference 26 corresponds directly to containment integrity reflood conditions. The injection flow rates for this group cover all phases and mixing conditions calculated during the reflood transient. The data from these tests were reviewed and discussed in detail in WCAP-10325-P-A (Reference 17). For all of these tests, the data clearly indicate the occurrence of very effective mixing with rapid steam condensation. The mixing model used in the containment integrity reflood calculation is, therefore, wholly supported by the 1/3-scale steam/water mixing data.

Additionally, the following justification is also noted. The post-blowdown limiting break for the containment integrity peak pressure analysis is the pump suction double-ended rupture break. For this break, there are two flow paths available in the RCS by which M&E may be released to containment. One is through the outlet of the SG, the other via reverse flow through the RCP. Steam that is not condensed by ECCS injection in the intact RCS loops passes around the downcomer and through the broken loop cold leg and pump in venting to containment. This steam also encounters ECCS injection water as it passes through the broken loop cold leg, upon which complete mixing occurs and a portion of it is condensed. It is the portion of steam that is condensed that is taken credit for in this analysis. This assumption is justified based on the postulated break location, and the actual physical presence of the ECCS injection nozzle. Descriptions of the test and test results are contained in WCAP-10325-P-A (Reference 17) and operating license Amendment No. 126 for D.C. Cook (Reference 25).

Table 6.2.1-3A presents the calculated M&E releases for the reflood phase of the pump suction double-ended rupture with the minimum safeguards (i.e., the diesel failure). Table 6.2.1-41 presents the reflood phase M&E releases for CPNPP Units 1 and 2 for the maximum safeguards cases.

The principal parameters during reflood are given in Table 6.2.1-3B and Table 6.2.1-42.

6.2.1.3.4.3 Post-Reflood Mass and Energy Release Data

The FROTH code (Reference 7) is used for computing the post-reflood transient. The FROTH code calculates the heat release rates resulting from a two-phase mixture present in the SG tubes. The M&E releases that occur during this phase are typically superheated (Reference 27) due to the depressurization and equilibration of the broken loop and intact loop SGs. During this phase of the transient, the RCS has equilibrated with the containment pressure. However, the SGs contain a secondary inventory at an enthalpy that is much higher than the primary side. Therefore, there is a significant amount of reverse heat transfer that occurs. Steam is produced in the core due to core decay heat. For a pump suction break, a two-phase fluid exits the core, flows through the hot legs, and becomes superheated as it passes through the SG. Once the broken loop cools, the break flow becomes two phase. During the FROTH calculation, ECCS injection is addressed for both the injection phase and the recirculation phase. The FROTH code calculation stops when the secondary side equilibrates to the saturation temperature (T_{sat}) at the containment design pressure, after which the EPITOME code completes the SG depressurization.

The methodology for the use of this model is described in WCAP-10325-P-A (Reference 17). The M&E release rates are calculated by FROTH and EPITOME until the time of containment depressurization. After containment depressurization (14.7 psia), the M&E release available to containment is generated directly from core boil-off/decay heat.

Tables 6.2.1-4 and 6.2.1-43 present the two-phase post-reflood M&E release data for the pump suction double-ended break cases.

6.2.1.3.4.4 Steam Generator Equilibration and Depressurization

SG equilibration and depressurization is the process by which secondary-side energy is removed from the SGs in stages. The FROTH computer code calculates the heat removal from the secondary mass until the secondary temperature is the saturation temperature (T_{sat}) at the containment design pressure. After the FROTH calculations, the EPITOME code continues the FROTH calculation for SG cooldown removing SG secondary energy at different rates (that is, first- and second-stage rates). The first-stage rate is applied until the SG reaches T_{sat} at the user-specified intermediate equilibration pressure, when the secondary pressure is assumed to reach the actual containment pressure. Then the second-stage rate is used until the final depressurization, when the secondary reaches the reference temperature of T_{sat} at 14.7 psia, or 212°F. The heat removal of the broken-loop and intact-loop SGs is calculated separately.

During the FROTH calculations, SG heat removal rates are calculated using the secondary-side temperature, primary-side temperature, and a secondary-side heat transfer coefficient determined using a modified McAdam's correlation. SG energy is removed during the FROTH transient until the secondary-side temperature reaches T_{sat} at the containment design pressure. The constant heat removal rate used during the first heat removal stage is based on the final heat removal rate calculated by FROTH. The SG energy available to be released during the first-stage interval is determined by calculating the difference in secondary energy available at the containment design pressure and that at the (lower) user-specified intermediate equilibration pressure, assuming saturated conditions. This energy is then divided by the first-stage energy removal rate, resulting in an intermediate equilibration time. At this time, the rate of energy release drops substantially to the second-stage rate. The second-stage rate is determined as the

fraction of the difference in secondary energy available between the intermediate equilibration and final depressurization at 212°F, and the time difference from the time of the intermediate equilibration to the user-specified time of the final depressurization at 212°F. With the current methodology, all the secondary energy remaining after the intermediate equilibration is conservatively assumed to be released by imposing a mandatory cooldown and subsequent depressurization to atmospheric pressure at 3,600 seconds, that is, 14.7 psia and 212°F (the M&E balance tables have this point labeled as "Available Energy")

6.2.1.3.4.5 Long- Term Mass and Energy Releases

The long-term post-one hour mass and energy releases (boil-off from core at the decay heating rate) are performed through user defined input functions in the GOTHIC code (Reference 18). This method of determining the long-term mass and energy releases is consistent with past long-term mass and energy releases is consistent with past applications of Westinghouse methodology.

6.2.1.3.4.6 Sources of Mass and Energy

The sources of mass and energy considered in the LOCA M&E release analysis are given in Table 6.2.1-54 for the DEHL break for CPNPP Units 1 and 2. The sources of mass for the DEPS break cases for CPNPP Units 1 and 2 are given in Tables 6.2.1-50 and 6.2.1-51. These sources are the RCS, accumulators, and pumped SI.

The energy inventories considered in the DEPS break M&E release analysis for CPNPP Units 1 and 2 are also given in Tables 6.2.1-50 and 6.2.1-51. The energy sources are the following:

- RCS water
- Accumulator water (all inject)
- Pumped SI water
- Decay heat
- Core-stored energy
- RCS metal (includes SG tubes)
- SG metal (includes transition cone, shell, wrapper, and other internals)
- SG secondary energy (includes fluid mass and steam mass)
- Secondary transfer of energy (feedwater into and steam out of the SG secondary)

The analysis used the following energy reference points:

- Available energy :212°F: 14.7 psia (energy available that could be released)
- Total energy content: 32°F; 14.7 psia (total internal energy of the RCS)

The M&E inventories are presented at the following times, as appropriate:

- Time zero (initial conditions)
- End of blowdown time
- End of refill time
- End of reflood time
- Time of broken-loop SG equilibration to pressure setpoint
- Time of intact-loop SG equilibration to pressure setpoint
- Time of full depressurization (3,600 seconds)

The energy release from the metal-water reaction rate is considered as part of the WCAP-10325-P-A (Reference 17) methodology. Based on the way that the energy in the fuel is conservatively released to the vessel fluid, the fuel cladding temperature does not increase to the point where the metal-water reaction is significant. For the LOCA M&E release calculation, the energy created by the metal-water reaction value is small and is not explicitly provided in the energy balance tables. The energy that is determined is part of the M&E releases and is therefore already included in the overall M&E releases for the CPNPP units.

The sequence of events for the CPNPP Units 1 and 2 LOCA design basis accident (DEPS MINSI) is shown in Table 6.2.1-9. The sequence of events tables for the DEHL and DEPS MAXSI break cases can be found in Table 6.2.1-11 and Table 6.2.1-12 respectively.

6.2.1.4 Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures

6.2.1.4.1 Plant Power Level

Steam line breaks can be postulated to occur with the plant in any operating condition ranging from hot shutdown to full power. Since steam generator mass decreases with increasing power level, breaks occurring at lower power generally result in a greater total mass release to the plant Containment. However, because of increased energy storage in the primary plant, increased heat transfer in the steam generators, and the additional energy generation in the nuclear fuel, the energy release to the Containment from breaks postulated to occur during power operation may be greater than for breaks occurring with the plant in a hot shutdown condition. Additionally, steam pressure and the dynamic conditions in the steam generators change with increasing power and have significant influence on both the rate of blowdown and the amount of moisture entrained in the fluid leaving the break following a steam line break event.

Because of the opposing effects of changing power level on steam line break mass and energy releases, no single power level can be singled out as a worst case initial condition for a steam line break. Therefore, a spectrum of power levels spanning the operating range (100.6 percent, 70 percent, and 30 percent of 3628 MWt), as well as the hot shutdown condition, has been considered. See Table 6.2.1-2A for the types of steam line breaks and power levels analyzed.

6.2.1.4.2 Break Type, Area, and Location

1. Break Type

There are two possible types of pipe ruptures which must be considered in evaluating steam line breaks.

The first is a split rupture in which a hole opens at some point on the side of the steam pipe or steam header but does not result in a complete severance of the pipe. A single, distinct break area is fed uniformly by all steam generators until steam line isolation occurs. The blowdown from the individual steam generator is not independent since fluid coupling exists among all steam lines.

The second break type is the double-ended guillotine rupture in which the steam pipe is completely severed and the ends of the break displace from each other. The effective break area is limited by the cross-sectional area of the flow restrictor that is integral to the steam generator. The reverse break area is the cross-sectional area of the pipe.

2. Break Area

The breaks analyzed include two break types (full double-ended and split rupture) at all four initial power levels as follows:

a. A full double-ended pipe rupture downstream of the steam line flow restrictor. For this case, the actual break area equals the cross-sectional area of the steam line, but the blowdown from the steam generator with the broken line is controlled by the flow restrictor throat area (1.4 ft^2). The reverse flow from the intact steam generators is controlled by the cross-sectional area of the pipe.

b. A split break that represents the largest break which will neither generate a steam line isolation signal from the primary protection equipment nor result in moisture entrainment. Steam and feedwater line isolation signals will be generated by high containment pressure signals for these cases.

3. Break Location

Break location affects steam line mass and energy releases by virtue of the pressure losses which would occur in the length of piping between the steam generator and the break. The effect of the pressure loss is to reduce the effective break area seen by the steam generator.

Although this would reduce the rate of depressurization, it would not significantly change the total release of energy to the Containment. Therefore, piping loss effects have been conservatively ignored in all blowdown results.

6.2.1.4.3 Main Feedwater Addition Prior to Feedwater Line Isolation

All of the double-ended ruptures generate main steam and feedwater isolation signals very quickly following the break. Isolation of these lines is assumed to be complete following a time

delay sufficiently long to conservatively allow for the instrument response time and signal processing delay and valve closing time (7 sec for feedwater line isolation and 7 sec for main steam line isolation).

For the split ruptures, feedwater line isolation signals (on the Safety Injection Actuation Signal) and main steam line isolation signals result from high Containment pressure protective trips. The setpoints for feedwater line and steam line isolation signals are assumed to be 5 psig and 8 psig, respectively. The isolation is assumed to be complete after a time delay sufficiently long to conservatively allow for the isolation as described above.

Prior to complete isolation, the depressurization of the steam generator results in significant amounts of feedwater being added to the broken loop steam generator through the main feedwater system. The quantity of feedwater added is conservatively evaluated using the following assumptions:

1. The two main feedwater pumps are conservatively operating at 5740 rpm (maximum turbine speed).

2. Prior to receipt of a valve isolation signal, all main feedwater control valves maintain the position that exists at "valves wide open" power operation, i.e., the valve feeding the faulted steam generator is fully open.

3. The main feedwater control valves in the intact loops maintain their initial flow until a valve isolation signal is received.

4. Immediate closure of the feedwater isolation valves and control valves in the intact loops upon receipt of the isolation signal. The control valves operate as a backup for the isolation valves. Control valves were originally procured to the requirements of ASME Code, Section III, Class 3; however, they are not required to be safety grade.

5. No flow reduction through the feedwater isolation valve and control valve in the broken loop prior to complete closure (i.e., no credit is taken for decrease in flow during valve closure or pump trip and coastdown).

6. For double-ended ruptures, the faulted loop main feedwater flow is modeled as a function of steam generator pressure, while the intact loops are kept constant at an initial flow. For split ruptures, the analysis conservatively models the main feedwater flow equal to the steam flow.

These assumptions were used along with the Feedwater System hydraulic resistances and pump performance curves to determine the amount of feedwater added to the steam generator with the broken loop over the range of steam generator pressures projected prior to feedwater isolation for each power level evaluated.

Based on the above assumptions (specifically, assumption number 3), the check valve in the feedwater line is not considered in a closed position. The analysis assumptions and results are consistent with those presented in Reference [6].

6.2.1.4.4 Auxiliary Feedwater System Design

Generally within the first minute following a steam line break, the Auxiliary Feedwater System is initiated on any one of several protection system signals. Addition of auxiliary feedwater to the steam generators increases the secondary mass available for release to the Containment as well as increasing the heat transferred to the secondary fluid.

The effects on steam generator mass are maximized in the calculation by assuming full auxiliary feedwater flow to the faulted steam generator starting at the time the ESF setpoint is reached and continuing until manually stopped by the plant operator. The time for manual action is assumed to be 600 sec after the break. The information available to the operator to manually isolate the auxiliary feedwater line to the faulted steam generator is described in Section 10.4.9.

The Auxiliary Feedwater System is equipped with flow restrictors which would limit the flow to a maximum of 1380 gpm to the steam generator with the broken line.

The mass and energy release data presented are conservatively based on an auxiliary feedwater addition of 1380 gpm to the steam generator with the broken line from the time of the protection system signal until 600 seconds after the break initiation.

6.2.1.4.5 Fluid Stored in the Feedwater Piping Prior to Isolation

The blowdown data were determined assuming a large value of 547 ft^3 of unisolated volume in the feedline supplying the steam generator with the broken line.

6.2.1.4.6 Fluid Stored in the Steam Piping Prior to Isolation

All the steam in the steam lines up to the turbine stop valve is assumed to be released to the Containment following the break. The volume of the initial steam released to the containment is 10,000 ft^3.

6.2.1.4.7 Availability of Offsite Power

Loss of offsite power following a steam line rupture would result in tripping of the reactor coolant pumps and the steam-driven main feedwater pumps, and a possible delay of auxiliary feedwater initiation due to emergency or diesel generator starting delays. Each of these occurrences aids in mitigating the effects of the steam line break releases by either reducing the fluid inventory available to feed the blowdown or reducing the energy transferred from the primary coolant system to the steam generators. Thus, blowdowns occurring in conjunction with a loss of station power are less severe than cases where offsite power is available; these cases are not presented.

6.2.1.4.8 Safety System Failures

1. Failure of Main Feedwater Line Isolation Valve

   One feedwater isolation valve and one feedwater control valve are located in series in each feedwater line. In this analysis, the assumed valve closure time is the design maximum main feedwater isolation time of 7 seconds.

Failure of one valve following a steam line break would increase the unisolable feedwater line by the volume between the two valves. This effect is included in the mass and energy release data presented.

No further consideration need to be given to this type of failure.

2. Failure of the Auxiliary Feedwater Pump Runout Protection

Limitation of maximum auxiliary feedwater flow to the broken loop steam generator is achieved through passive flow restrictors. Failure of passive flow restrictors is not considered credible.

3. Failure of Main Feedwater Pump Trip

No credit is taken for feedwater pump trip and coastdown in calculating main feedwater addition prior to feedwater line isolation. Therefore, this failure has no effect on the results presented.

4. Failure of a Steam Line Stop Valve

Failure of a main steam line stop valve increases the volume of steam piping which empties into the Containment.

The effects of this failure on calculated Containment pressures and temperatures were compared with the effects of the failure of one Containment spray train. With respect to the maximum Containment pressure, calculations showed that the adverse effect of a steam line stop valve failure was more than that of one Containment spray train failure for the full power cases and less than that of one containment spray train failure for the 70 percent, 30 percent and hot zero power cases. With respect to the maximum Containment temperature, the adverse effect of a steam line stop valve failure was greater than that of one containment spray train failure.

5. Failure of One Containment Spray Train

The failure of one of the two redundant Containment spray trains following a main steam line break results in reduced ability to remove energy from the Containment atmosphere.

A time delay following a Containment pressure signal is necessary to incorporate delays for the instrumentation signal response, diesel generator start, pump load sequencing, pump acceleration, Containment isolation valve opening and system fill time.

The greater timing of containment spray setpoints and delays are modeled:

- 74.3 seconds after the containment reaches the Containment S signal setpoint (5 psig), or

- 52.5 seconds after the containment reaches the Containment P signal setpoint (20 psig)

Full flow conditions are achieved for both after the delay time is assumed.

6.2.1.5 Minimum Containment Pressure Analysis for Performance Capability Studies of Emergency Core Cooling System

The Containment backpressure is calculated using the methods and assumptions discussed in Section 15.6.5.3. Input parameters including the Containment initial conditions, net free Containment volume, passive heat sink materials, thicknesses, and surface areas and starting time and number of Containment cooling systems used in the analysis are described in the following paragraphs.

6.2.1.5.1 Mass and Energy Release Data

The mathematical models which calculate the mass and energy releases to the Containment are described in Reference 9. These methods are similar to the models used to perform the original analysis of the large break LOCA to meet the requirements of Appendix K. Since the requirements of Appendix K of 10 CFR Part 50 are very specific in regard to the modeling of the RCS during blowdown and the models used are in conformance with Appendix K, no alterations to those models have been made in regard to the mass and energy releases. A break spectrum analysis is performed that considers various break sizes, break locations, and Moody discharge coefficients for the DECLGs which do affect the mass and energy released to the Containment. This effect is considered for each case analyzed.

6.2.1.5.2 Initial Containment Internal Conditions

The initial values used in the analysis are provided in Section 15.6.5.

The Containment initial conditions are representatively low values anticipated during normal full power operation. In addition, the RWST temperature and outside air temperature assume minimum operational values.

6.2.1.5.3 Containment Volume

The net free volume is calculated by subtracting the volume of internal structures and equipment from the gross volume of the Containment.

Only the following are considered in the determination of the volume of internal structures and equipment:

1. Volume of internal concrete walls and floors

2. Volume of the major components of the RCS

The volumes of internal steel structures and supports, cranes, tanks, and other miscellaneous equipment are neglected.

This results in a conservatively high Containment net free volume of 3.063×10^6 ft^3.

6.2.1.5.4 Active Heat Sinks

The CSS operates to remove heat from the Containment.

CSS data has been determined as follows:

1. The maximum flow rate is based on maximum water level in the Refueling Water Storage Tank (RWST) and minimum Containment pressure necessary for Containment spray actuation. Both of these conditions concurrently will produce minimum Containment spray pump RDH during injection and consequent maximum flow.

   This is conservative because the actual RWST level will be falling and the actual Containment pressure will be higher.

2. The minimum time for post LOCA initiation of Containment Spray System operation with a loss of offsite power is based on the time required for diesel generator starting and loading of the spray pumps plus the minimum time in which the spray pumps can fill the spray headers up to the first spray nozzle. This is conservative since the spray pump flow will actually be limited during pump startup to a lower rate to protect the pumps from a runout trip.

The sump temperature was not used in the analysis because the maximum peak cladding temperature occurs prior to initiation of the recirculation phase for CSS.

6.2.1.5.5 Steam Water Mixing

Water spillage rates from the broken loop accumulator are determined as part of the core reflooding calculation and are included in the Containment calculation model.

6.2.1.5.6 Passive Heat Sinks

The surface areas and thicknesses of internal concrete walls and floors were calculated using detailed structural drawings.

The surface areas were increased to include an estimated error in the calculations.

The concrete floor thicknesses were increased by maximum thickness of floor finish.

The surface areas and thicknesses of mechanical equipment were calculated using detailed manufacturer's drawings. The surface areas and thickness of piping and HVAC ducts were calculated using detailed mechanical drawings of actual layout.

Surface areas and thicknesses were calculated to be conservatively high.

The resistance to heat absorption caused by layers of protective coating on heat sinks is conservatively neglected. Similarly, any potential airgap between the steel liner and concrete is also ignored.

The thermophysical properties of steel and concrete are in conformance with Reference 4.

6.2.1.5.7 Heat Transfer to Passive Heat Sinks

The condensing heat transfer coefficients used for heat transfer to the steel Containment structures are included in the Containment calculation model.

6.2.1.5.8 Other Parameters

No other parameters have a substantial effect on the minimum Containment pressure analysis.

6.2.1.6 Testing and Inspection

Preoperational and periodic inservice tests are conducted to ensure the functional capability of the Containment and associated systems. The tests are discussed in the following Sections:

Section	Test
5.4.7	Residual heat removal
6.2.2	Containment spray and sump tests
6.2.6	Containment leakage test including integrated leakage rate test, penetration leakage rate test, and isolation value leakage rate test

6.2.1.7 Instrumentation Requirements

The reactor coolant pressure boundary (RCPB) leakage during normal plant operation is detected by Containment air particulate monitors, radioactive gas monitors, Containment sump flow monitors, Containment dewpoint monitors, Containment cooling coil condensate measurement and other means as discussed in Section 5.2.5. If the level of leakage is excessive, Control Room alarms are sounded, and ventilation air ducts are automatically or manually closed in order to isolate the Containment atmosphere from the environment.

In addition, instrumentation which monitors process parameters is used to actuate ESF systems. These parameters are pressurizer pressure, Containment pressure, steam line pressure, steam line differential pressures, steam flows, and RCS average temperature. When the values of these parameters fall outside of predetermined setpoints, the actuating signals are generated. The design details and instrumentation logic are presented in Sections 7.2 and 7.3.

The postaccident monitoring is discussed in Section 7.5.

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6.2.2 CONTAINMENT HEAT REMOVAL SYSTEMS

The Containment Spray System (CSS) is designed to remove heat from the Containment environment following a LOCA, a main steam line break accident, or a feedwater line break accident. Major components of the CSS are the RWST, Containment spray pumps, Containment spray heat exchangers, spray headers, spray nozzles, and Containment recirculation sumps.

Each unit of the CPNPP is equipped with two redundant Containment spray trains, each designed to provide emergency Containment heat removal in the event of a LOCA. This system, in conjunction with the ECCS, removes postaccident thermal energy from the Containment environment, thereby reducing the Containment pressure and temperature.

6.2.2.1 Design Bases

The CSS is a nuclear-safety-related system and is classified as seismic Category I. The system is designed in accordance with NRC Regulatory Guides 1.1, 1.26, 1.29, and 1.82 and in accordance with GDC 38, 39, 40, 41, 50, and 56 of Appendix A of 10 CFR Part 50.

The CSS operation is divided into two phases, initially operating in the injection phase and then the recirculation phase. Two redundant and physically separated spray trains are provided for the CSS. Each train draws spray water from a common RWST during the injection phase and from separate recirculation sumps during the recirculation phase. The failure of any single active component during the injection or recirculation phase or failure of a single passive component during the recirculation phase does not prevent safe operation of the system.

Each train is designed to deliver a minimum of 5800 gpm of cold water (≤120°F) to the spray nozzles during the injection phase of system operation. This is sufficient to maintain the Containment pressure and temperature below Containment design values. The postaccident Containment pressure is reduced to half its value in 24 hours. The sources and amount of energy taken into consideration are described in Subsection 6.2.1.

Each Containment spray train is designed with a heat removal capacity during the recirculation phase sufficient to maintain the pressure and temperature in the Containment below design values for a long period of time until the decay heat generated by the reactor fuel is reduced to the level at which the heat can be removed from the Containment by other systems or by natural heat transfer.

Each Containment spray train is provided with a chemical additive subsystem which is designed to remove fission products from the Containment atmosphere. The chemical additive subsystem is described in Section 6.5.

To ensure proper performance during accident conditions, the CSS equipment and components are designed for the environmental conditions discussed in Section 3.11B. Additional equipment design criteria are given in Table 6.2.2-1.

The CSS has been designed in accordance with the requirements of the ASME B&PV Code, Section III, and NRC Regulatory Guide 1.29 to ensure the capability of the system to withstand the Safe Shutdown Earthquake (SSE) without loss of its safety function. Dynamic effects resulting from the fluid transient of the CSS operation have been evaluated at CPNPP.

Pipe whip restraints are located on adjacent high-energy lines to prevent a broken pipe from whipping and damaging components unacceptably in the CSS as described in Sections 3.5 and 3.6.

The system is designed to allow periodic determination of proper functioning to demonstrate system readiness. Routine testing is performed periodically to verify the operability of system components.

6.2.2.2 System Design

The CSS, which is shown on Figure 6.2.2-1, is an ESF specifically provided to mitigate the consequences of a LOCA, a steam line break, or a feedwater line break inside the Containment. The CSS has the dual function of removing heat and fission products, especially radioactive iodine, from the postaccident Containment atmosphere. Acting in conjunction with the ECCS, which maintains cooling of the reactor core after a LOCA, the CSS ensures that a LOCA does not jeopardize Containment functional design. To reduce transient pressure and temperature and to remove the fission products in the Containment following an accident, water is sprayed into the Containment atmosphere through a large number of spray nozzles mounted on ring headers which are located in the Containment dome and on headers in lower areas of the Containment. Because of the large surface area of the solution drops sprayed into the Containment atmosphere, large amounts of heat and elemental iodine are absorbed into the spray drops as they fall through the Containment atmosphere to the sump. The spray water flow path is as follows: water flows from the spray nozzles, falls through the Containment atmosphere, washes the Containment walls, washes down the steam generators, reactor coolant pumps and piping, and floors, and thereby reaches the Containment sump suction lines.

The CSS has two modes of operation, the injection phase and the recirculation phase.

Initiation of the injection phase begins after a LOCA, when the Containment spray pumps start on an S signal. The Containment spray header discharge valves open on a P signal. A detailed description of the generation of S and P signals is provided in Section 7.3, Engineered Safety Features Actuation System. Set points for the ESF Actuation System are given in unit Technical Specifications. These set points have been established to provide sufficient time for initiation of CSS operation and performance of its safety function.

The pumps take suction from the RWST and discharge the solution inside the Containment. To enhance iodine removal and ensure retention of the iodine and to adjust the pH value of the spray solution to inhibit chloride stress corrosion of stainless steel components, a chemical additive subsystem is provided to inject sodium hydroxide into the spray water during this phase (Section 6.5.2.). The sequence of events which occur prior to initiation of Containment spray, as well as the timing involved, is summarized in Table 6.2.1-9.

After ECCS Switchover (Section 6.3.2.8) is complete, the suction of the Containment spray pumps is shifted by the operator to the Containment recirculation sumps where injection water, reactor coolant, and accumulator spillage have collected. This water is sprayed into the Containment again after having given up its heat to the component cooling water via the Containment spray heat exchangers.

Makeup to the RWST is obtained from the Reactor Makeup Water Storage Tank (RMWST) by manual operation using the reactor makeup water transfer pumps and the CVCS blender to maintain required boron concentration in the RWST.

Using the demineralized water transfer pumps, makeup to the spray headers inside the Containment is obtained from the demineralized water storage tank by manual operation. The makeup connection is provided above the operating floor at elevation 905 ft 9 inches. A level switch is provided to monitor the level in the spray header riser during plant operation.

Makeup to the containment spray pump suctions piping located downstream of the containment isolation valves is also obtained from the demineralized water storage tank by manual operation using the demineralized water transfer pumps, a local drain valve and hose connection.

Redundancy requirements of the CSS are satisfied by providing duplicate components of 100 percent capacity. The total heat removal function can be accomplished with the use of two pumps, one heat exchanger, and one train of nozzles. Each train is supplied by one suction line from a Containment spray recirculation sump. With the exception of the RWST and the chemical additive subsystem, both Containment spray trains are completely separated for the heat removal function. For more information on the CSS design parameters and the Containment design parameters, refer to Tables 6.2.2-2 and 6.2.2-3, respectively.

6.2.2.2.1 Component Description

Additional equipment design criteria is given in Table 6.2.2-1. A detailed description of environmental qualification verifications performed on CSS components is given in Section 3.11. For a detailed description of the chemical additive subsystem, spray headers, and nozzles, refer to Section 6.5.2.

1. Containment Spray Heat Exchangers

   Two Containment spray heat exchangers are provided for each unit. The heat exchangers are of the vertical shell and U-tube type. They are designed in accordance with the requirements of the ASME B&PV Code, Section III, and in accordance with TEMA Class R for those items not covered by the ASME B&PV Code Section III. The tube side of each heat exchanger is classified ASME B&PV Code Class 2, and the shell side is ASME B&PV Code Class 3. The heat exchangers are designed to seismic Category I requirements.

2. Containment Spray Pumps

   Four Containment spray pumps are provided for each unit and are of the horizontal, double-suction, split-case, centrifugal type. The pumps are designed to the requirements of the ASME B&PV Code, Section III, Class 2, and are designed to seismic Category I requirements.

   Each pump is capable of delivering 3000 gpm with a total dynamic head (TDH) of 585 ft, which includes the sum of the Containment design pressure (50 psig), the nozzles elevation head, the nozzle pressure drop (40 psi), the line losses, and a 5-percent margin. The pump design temperature and pressure are 300°F and 325 psig, respectively.

Each pump is driven by a three-phase, 60-Hz, 6600-V, 700-hp motor.

3. Valve Isolation Tanks

The Containment recirculation sump isolation valves are enclosed in valve isolation tanks. These tanks are not part of the Containment barrier. Therefore, the tanks are not tested to Containment design conditions.

4. Refueling Water Storage Tank

One RWST is provided for each unit. This tank, located outdoors, serves as a source of emergency borated cooling water during injection and as the source of refueling water during refueling operations. The tank consists of a concrete structure lined with stainless steel plate and is designed to seismic Category I requirements. It is designed to withstand tornado loadings and tornado generated missiles. Freeze protection is provided by operating a Containment spray pump in a recirculation mode through the test line, which returns to the tank, to maintain the tank temperature above 40°F. If necessary additional heat can be provided, by operating a residual heat removal (RHR) pump in addition to the Containment spray pump.

5. Spray Nozzles and Ring Headers

The nozzles are of one-piece construction, with a 3/8-in. diameter orifice and produce a hollow cone spray pattern.

The spray nozzles are installed on ring headers in the Containment dome and spray headers at lower elevations in the Containment. The nozzle arrangement is designed to provide maximum coverage inside the Containment. Refer to Section 6.5.2 for a detailed description of the spray header location and spray coverage. The spray header piping is designed in accordance with the ASME B&PV Code, Section III, Class 2, and the requirements of seismic Category I. The spray nozzles are designed in accordance with manufacturer's standards which include applicable requirements of the ASME B&PV Code, Section III, Class 2.

6. Piping and Valves

The piping and valves of the CSS are designed in accordance with the ASME B&PV Code, Section III, Class 2, and seismic Category I requirements. They have the following characteristics:

a. The piping and valves for the CSS are designed to 325 psig and 300°F. The pump suction lines from the recirculation sumps and the RWST are designed to 70 psig and 300°F.

b. The motor-operated isolation valves in the recirculation lines are totally enclosed in valve isolation tanks. The recirculation lines that run from the sumps to the Containment spray pumps are protected by concentric guard piping up to the valve isolation tanks. These tanks are used to control leakage and are not tested at Containment design conditions.

c. All piping and valves used for the CSS are stainless steel.

7. Containment Spray Recirculation Sumps

The design of the Containment spray recirculation sumps satisfies the requirements of NRC Regulatory Guide 1.82, Sumps for Emergency Core Cooling and Containment Spray Systems as described in Appendix 1A(B). Two sumps are provided, one for each safety train. The sumps are physically separated and are located at the lowest elevation of the Containment Building exclusive of the reactor vessel cavity. Sump covers are provided to protect the sumps against falling debris. Stainless steel strainers are provided to preclude clogging of the recirculation lines and any of the system's components. The strainers have nominal 0.095 inch holes in perforated plate. The size of the opening ensures that the 3/8-in. diameter spray nozzle orifices and the grid assemblies in the reactor core do not clog. It is required that suction piping to the containment recirculation pumps be arranged such that vortexing does not occur (i.e., no vertical pipe with downward flow or horizontal pipe with inadequate submergence). To prevent the possibility of vortex formation, the suction is fitted with a conical opening and a grating cage (Figure 6.2.2-3). The sump strainer design provides natural vortex suppression in addition to the suction inlet design. The arrangement of the recirculation sumps, including design provisions for the prevention of vortex formation in the recirculation sump piping of RHR and containment spray lines, is shown in Figure 6.2.2-3 and 6.2.2-3A.

ECCS fluid collecting in the reactor refueling cavity is returned to the containment sump through the drain lines provided in the design of the refueling cavity. To prevent blockage in the main refueling cavity, debris strainers are provided for the 4 inch drain and debris screens are provided for the two 6 inch drains. The part plan and elevation of the reactor refueling cavity at elevation 831'-6" are shown in Figure 6.2.2-4 and Figure 6.2.2-5. The refueling cavity consists of an upper internals storage stand area (floor elevation 831'-0"), a central portion (floor elevation 834'-0 1/2") and the lower internals storage stand area (floor elevation 823'-0 1/2"). The upper internals storage stand area and the lower internal storage stand area communicate hydraulically through a 4 inch equalization line. This line is imbedded and not subject to mechanical damage. Following an accident the ECCS fluid reaching the upper internals storage stand area will drain to the lower internals storage stand area from where it will be drained to the 808'-0" elevation through the drain lines as shown on Figure 6.2.2-5. The fluids that reach the fuel transfer upender area will be drained to the 808'-0" elevation through a separate drain line. To prevent blockage in the upender area of refueling cavity, a debris strainer is provided for the 4 inch drain.

6.2.2.2.2 Electrical Requirements

Each train is electrically supplied from a separate and independent Class 1E bus which is capable of supplying the minimum safety-related loads required following a LOCA or a loss of offsite power (blackout), or both. Each bus can be powered from two independent offsite power sources or by one onsite power source (diesel generator) assigned to the bus. Loads which are required for safe shutdown of the unit are supplied power from a Class 1E power supply. Other loads are supplied power from a non-Class 1E power supply.

In the event of a LOCA or loss of all offsite power (blackout), or both, Containment spray pumps and their associated motor operated valves are automatically sequenced onto their respective emergency buses as follows:

Component	Start Time After SIAS (Sec)
Motor-operated valves	10(1)
Containment spray pumps	25

1) For motor operated valves, this is the time at which the respective motor control centers are re-energized. The valves are capable of operation, but will not operate unless a "P" signal is received.

Motor-operated valves stop automatically when valve action is completed. Containment spray pumps must be manually stopped.

6.2.2.3 Design Evaluation

6.2.2.3.1 Containment Spray Nozzles

Spray Engineering Company's model 1713A nozzle has been found acceptable in experiments with Containment spray iodine removal systems. This type of nozzle is discussed in more detail in Section 6.5.2.

Clogging of nozzles is precluded by providing a 0.115-in. mesh screen over the recirculation sumps. Since the nozzle orifice is 3/8-in.diameter, and the screen does not pass particles larger than 0.115-in. nominal size, nozzle clogging is prevented.

The CSS is designed to maintain a 40 psi differential pressure across each nozzle. All spray nozzles on one train are permanently connected through the system with two Containment spray pumps and one heat exchanger.

The total flow of one train is distributed so that each single spray nozzle passes 15.2 gpm nominal flow, and on the basis of this information, the drop size spectrum emitted from the nozzle has been established. The criteria used concerning drop size is as follows:

1. The data concerning the drop size distribution are taken from testing performed by Spray Engineering Company's laboratory on the spray nozzle model 1713A [1].

2. The droplet size and droplet distribution were recorded by high speed photographic methods, using a droplet measurement chamber. This method is considered the most accurate known, and among the 65 nozzles which have been tested, variance from nozzle to nozzle was insignificant.

3. Since the method of measurement uses high speed photographic techniques which involve stop motion, the data are considered as a spatial distribution, whereas a temporal

distribution would be the true distribution after taking into consideration the effect of velocity.

4. A cross section through the spray cone was analyzed. For this measurement, a chamber was constructed to house the photographic equipment making it possible to penetrate the spray cone. The photographic equipment was mounted on a traversing rack, which could be traversed outward from the spray axis.

5. Each quadrant of the cone was divided into eight zones, permitting the collection of a total of 32 sample points. From a quantity of 325 nozzles, 65 nozzles were randomly selected for testing.

In the high temperature postaccident Containment atmosphere an increase in drop size can occur as a result of steam condensing on the spray drops. Through the use of a mass balance approach, Pasedag and Gallagher [2] have shown that the change in drop size distribution can be modeled by a step increase to the equilibrium size immediately after the drops emerge from the nozzle.

Plan and elevation drawings are shown on Figure 6.5-4.

The Containment coverage is described in more detail in Section 6.5.2.

6.2.2.3.2 Heat Removal Capability

The CSS limits the effects of postblowdown energy addition so that the effects are within the design capabilities of the Containment during the injection phase following a LOCA.

Containment pressure-temperature analyses detailed in Section 6.2.1 assume that Containment cooling capability is reduced to one spray train. This is the minimum equipment available considering the single failure criterion in the emergency power or the CSS.

The heat removal capability of the CSS is dependent on the ability of spray droplets to condense steam from the high-temperature postaccident Containment environment. A spray droplet, which enters the Containment after a LOCA encounters a saturated steam-laden atmosphere. Since the vapor pressure of the droplet is much lower than the partial pressure of steam in the Containment air, steam diffuses to the drop surface, where condensation occurs. This mass diffusion of steam is a vehicle for energy transfer to the droplet, which causes the droplet temperature, the resultant vapor pressure, and the size of the droplet to increase until thermal equilibrium is reached with the partial pressure of steam. When this occurs, condensation ceases, and no further heat removal is possible by that droplet.

Calculations of heat and mass transfer of a droplet are based on the use of heat transfer and mass transfer coefficients, which are derived from the Nusselt number for heat transfer (Nu_t) and the Nusselt number for mass transfer (Nu_m). These may be calculated from the following equations of Ranz and Marshall:

$$Nu_t = 2 + 0.6\,(Re)^{1/2}\,(Pr)^{1/3}$$

$$Nu_m = 2 + 0.6\,(Re)^{1/2}\,(Sc)^{1/3}$$

where

Re = Reynold's number
Pr = Prandtl's number
Sc = Schmidt's number

Analysis shows that a droplet with the mean droplet diameter reaches equilibrium even before it falls half the available spray fall height, which is conservatively assumed to be the distance from the lowest ring header to the operating deck.

Calculations performed based on the methodology established by Parsly [3] [4] show that the overall thermal efficiency of spray droplets in cooling the Containment atmosphere is greater than 0.99. However, a spray thermal efficiency lower than 0.99 at full spray flow was used in the analysis.

6.2.2.3.3 Recirculation Sump Design

In response to Generic Letter 2004-02 [Ref. 6], the emergency sump design was modified to replace the flat screen based design with a complex strainer based design with an effective factor of 20 increase in surface area. An analysis of the susceptibility of the ECCS and CSS recirculation functions for Units 1 and 2 was performed. This analysis provides plant specific evaluations of upstream effects, debris generation, and debris transport to the ECCS and CSS recirculation sump. The head loss associated with debris accumulation, and its associated effect on available net positive suction head were demonstrated by testing. The structural capability of the sump strainers under debris loadings was also evaluated. The downstream effects of debris that passes through the screens on components in the recirculation flow path such as pumps, valves, orifices, spray nozzles, and core components were also evaluated. The testing and analyses provide the basis to show compliance with the applicable regulatory requirements including 10CFR50.46; 10 CFR 50 Appendix A, General Design Criteria 35, 38 and 41; and 10CFR100.

The NRC has approved the methodology for meeting Generic Letter 2004-02 using the guidance of Nuclear Energy Institute (NEI) document titled "*Pressurized-Water Reactor (PWR) Sump Performance Methodology*," dated May 28, 2004 as approved and supplemented by the NRC in an SER dated December 6, 2004. The sump performance methodology and the associated NRC SER have been issued collectively as NEI Report NEI 04-07, "Pressurized Water Reactor Sump Performance Evaluation Methodology," Revision 0, dated December 2004. [REF. 7]

The methodology used employs plant specific refinements, as allowed by the NRC SER. Additional data and methodology from ongoing research on specific issues such as downstream effects, chemical effects, and coatings were also used to the extent possible. The methodology was supplemented with plant specific design and licensing basis information and contractor specific proprietary information and data as appropriate with the current state of knowledge. Exceptions and/or interpretations being taken to the guidance given in NEI 04-07 as modified by the SER are described in the responses to the Generic Letter.

All of the thermal insulation inside the Containment on both piping and equipment is of the reflective (mirror) type, composed of stainless steel. All antisweat insulation inside containment is low to medium density fiberglass jacketed in stainless steel. Vapor barrier materials are not permitted.

All of the high efficiency thermal insulation is composed of fibrous media and very fine heat resistant particulate matter, totally encased in stainless steel.

Thermal insulation is attached by use of quick release fasteners, buckles, straps, or bands. All reflective insulation, with the exception of the reactor coolant pipe insulation inside the primary shield concrete, is designed to remain in place during an SSE. Sample typical panels of insulation are seismically tested to confirm the design. A series of pressurization tests are also performed to ensure that the insulation maintains its structural integrity under postaccident pressures as well as Containment structural acceptance test and leakage rate test pressures. A thermal transient test is performed on sample insulation panels to ensure that the insulation maintains its structural integrity during postaccident temperature transients. This test consists of heating the sample panel to 650°F and quenching with cold water.

The reflective insulation assemblies are specified to withstand seismic forces resulting from acceleration of 3g in both horizontal directions and 3g in the vertical direction caused by the SSE. As a result of the Steam Generator Replacement Project, the accelerations for the Unit 1 steam generators, the new main feedwater piping and the new auxiliary feedwater piping are location specific. The insulation structural mounting frames and panel attachments to the mounting frames are designed to maintain their structural integrity during the SSE.

In order to verify that the insulation meets the required seismic criteria, the insulation supplier has tested a typical assembly on a generic basis. The tests consisted on an initial sinusoidal input frequency between 3 and 100 Hz to determine the resonant frequency condition followed by an endurance test at the lowest resonant frequency. The insulation assembly was subjected to 10g's in both the horizontal and vertical directions with following visual inspections. No damage or distortion to the structure was observed.

It is also anticipated that only that portion of insulation which is covering the actual break area and any other insulation subject to jet impingement effects are dislodged during a LOCA. Since the thermal insulation in the vicinity of postulated Reactor Coolant System (RCS) or main steam line breaks is of an all-metal reflective type or for the main steam and feedwater piping underneath the pipe whip restraints, high efficiency thermal insulation totally encased in stainless steel, the major portion of dislodged insulation sinks rapidly and remains in the area of the break. As demonstrated by testing, any pieces of reflective insulation which are carried by high-velocity streams of water out of the steam generator compartment tend to settle in the low-velocity area approaching the recirculation sumps. Analysis and testing of potential debris sources has shown that the primary debris of concern for sump performance is the combination of fibrous debris, particulate, and chemical precipitate. Fibers from fiberglass antisweat insulation located on cooling and chilled water lines and from latent debris are capable of transporting to the strainer surface. The covers for lead shielding blankets also contain fiberglass which could be within the zone of influence of a LOCA. High efficiency thermal insulation (Min-K) is made of both fibrous and particulate materials. Particulate of concern includes latent debris and coating debris. The chemical precipitates of concern result from the interaction of containment spray with aluminum. Debris generation analyses have conservatively determined bounding quantities of these and other materials that could be generated by a loss of coolant accident or a secondary line break.

The radiation protection doors from the steam generator compartments located at Elevation 808 are designed with bars in lieu of wire mesh to ensure that blockage of water and debris from a LOCA or a secondary line break does not occur. The door to the incore instrumentation guide tube room and the floor barrier around the tubes are similarly designed to ensure blockage does

not occur for a LOCA or secondary line break. This design, in conjunction with the debris interceptor around the emergency sumps, ensures that transport of small debris to the large inactive sump under the reactor vessel is maximized. Debris which is transported to the inactive sump cannot affect sump performance during recirculation. Debris transport analysis has conservatively determined bounding quantities of the materials identified in the debris generation analyses that could be transported to the vicinity of the recirculation sumps. In addition to particulate and fiber, latent debris was assumed to include labels, tape, and other miscellaneous materials which could be present in containment. The results of the debris generation and debris transport analyses are combined to determine the design basis debris load for strainer qualification testing. See Section 6.2.2.3.4.

Containment sump strainer design is in accordance with the intent of Regulatory Guide 1.82. See Appendix 1A(B) for a discussion of conformance to RG 1.82.

Each of the two Containment recirculation sump strainers has a total surface are of approximately 3,947 square feet and consists of 36 modules, each with seven vertical (stacked) disks made from perforated plate. The sump strainer design ensures that the strainer are capable of withstanding the force of full debris loading, hydrodynamic loads and inertial effects of water in the containment recirculation pool, in conjunction with all design basis design conditions, including seismic, without collapse or structural damage. The sump strainer design is robust enough so that the disks also perform the same function as a trash racks. Large floating debris would not be able to block significant flow or surface area of the strainer. Trash racks are provided on the inboard side of the strainers to protect them from incidental damage during outages. Because the strainers perform the trash rack function, the trash racks are non-safety related, seismic Category II and are not required to meet RG 1.82.

A one foot tall solid debris interceptor is provided around each of the strainers. The safety function of this interceptor is to stop tumbling debris such as reflective insulation, coatings, labels, and other miscellaneous debris. This design feature will significantly reduce the debris which could reach the strainer in a design basis event. The largest quantity of debris generated by a LOCA jet would be reflective insulation which transports by tumbling along the floor. Testing has shown that reflective metal insulation debris will not transport to the strainers and that this debris is beneficial in that it would capture, and/or impede the transport of, fibrous debris. However, no credit for the beneficial aspects of RMI was taken in the analyses or testing.

Containment inspection procedures are in place to ensure the containment recirculation sumps are cleared of items that could potentially block the sumps. In addition, plant operating procedures provide information to the operators concerning indicators, probable cause, and actions to be taken in the event of low flow due to sump blockage or vortexing.

The refueling cavity is equipped with two (2) 4 inch drains located at el. 823'-0.5" and 819'-6 3/4" respectively, both discharging to el. 808'-6". These drains are covered by debris strainers making their clogging unlikely. Two redundant 6 inch drains are also provided in the refueling cavity at elevation 823’-0.5”. Each is covered with a speciality designed debris screen to prevent blockage by large insulation debris. One of these 6” drains is sufficient to drain the main area of the refueling cavity. The 4 inch drain and debris strainer in the main area of the refueling cavity provides a diverse drain path which is capable of assuring minimal water holdup. The upender area of the refueling cavity, with the drain at el. 823’, is connected to the main area of the refueling cavity by a gate opening at approximately el. 834’. Therefore, the 6 inch drains provide a diverse drain path which is capable of assuring limited water holdup.

There are no sand plug materials or structures inside the Containment designed to be displaced by accident pressures to provide vent areas. Consequently, this is not a source of debris.

The coating systems specified for use inside the Containment are qualified for postaccident Containment environment. See Section 6.1B.2 for additional details.

Any concrete particles or miscellaneous steel such as ductwork stairs or grating which may be displaced by differential pressure or jet impingement tend to sink in the low-velocity area approaching the screens.

All temporary materials used during refueling or maintenance outages, such as paper, plastic sheeting, or temporary wooden scaffolding, are removed from the Containment prior to operation.

6.2.2.3.4 Net Positive Suction Head

Sufficient net positive suction head (NPSH) is available to the Containment spray pumps for both the injection and recirculation modes of operation.

During the injection phase, the NPSH is calculated using the atmospheric pressure in the RWST, the static head between the suction sparger and the pump elevation, the piping losses, and the vapor pressure of water at 120°F.

During the recirculation phase, adequate NPSH for the Containment spray pump is ensured by the design of the CSS in accordance with NRC Regulatory Guide 1.1. It is assumed that the Containment ambient pressure is equal to the vapor pressure of the sump liquid.

The CPNPP design assumes that a water volume equal to the volume of the reactor incore instrumentation pit (between elevations 783'-7 and 808'-0) is trapped immediately following an accident and not available for recirculation. This trapped volume of water was also deducted from total volume when the available NPSH for containment spray pumps was calculated.

The available NPSH for the containment spray pumps during the recirculation phase was determined as follows:

NPSH = Static Head - Piping Friction Losses - Entrance Losses - CSHL

Where: CSHL is the Clean Strainer Head Loss.

The static head calculation considers only the difference between the elevation of the Containment Spray pumps' impeller centerline and the minimum calculated containment water level during the containment spray system recirculation phase.

Figure 6.2.2-2 shows the relationship between the available NPSH and the pump flow during the injection and recirculation phases and shows the required NPSH. Design parameters for the pumps are shown in Table 6.2.2-1.

The NPSH margin is calculated based on a clean strainer and minimum containment water levels during containment spray recirculation. The design basis debris head loss is determined by

prototypical testing of a full size trainer with the design basis debris load as described in Section 6.2.2.3.3 scaled to the test configuration. This testing has shown that significant NPSH margin remains after the design basis debris head loss is subtracted from the clean strainer NPSH margin.

6.2.2.3.5 Single Failure Analysis

A failure analysis of all active components of the heat removal systems during the injection phase and all active and passive components during the recirculation phase shows that the failure of any single component does not prevent performance of the design function. This analysis is summarized in Table 6.2.2-5.

6.2.2.4 Tests and Inspections

6.2.2.4.1 Inspections

The CSS is designed to permit periodic determination of proper functioning to demonstrate system readiness.

The Containment spray pumps and heat exchangers are located outside the Containment to permit access for periodic inspection and testing during normal plant operation. The pressure-containing systems are inspected for leaks from pump seals, valve packings, flange joints, and safety valves during system testing. A full flow test line is provided for the pumps to allow for periodic testing, of each train during which water is recirculated to the RWST.

The spray nozzles are not to be tested insitu with water. However, a CSS full-flow ring header test was performed at Zion Nuclear Power Plants - Units 1 and 2 (Docket Nos. 50-295 and 50-304). This test demonstrated that the flow which passed through the system was as designed, that there was no discernible movement in the ring headers when subjected to spray flow forces, and that the Containment coverage was as predicted.

The CSS is subject to periodic inservice inspection by volumetric, surface and visual examination techniques in accordance with Section 6.6. Also, control equipment is checked to verify that the CSS is in a state of readiness. Performance curves and NPSH requirements have been supplied by shop tests for new pumps and expected performance curves based on generic and field tests when new impellers were provided in place of pumps, to confirm pump design characteristics. The associated NPSH set of these curves is shown on Figure 6.2.2-2.

Performance data for spray nozzles are provided in Section 6.5.2.2.1 to verify maximum droplet mean diameter. These data are the result of manufacturer's shop tests.

6.2.2.4.2 Preoperational Testing

Outside the Containment, piping welds are subjected to 100-percent radiographic inspection and hydrotesting, while inside the Containment, the spray header welds are subjected to 100-percent radiographic inspection. These tests demonstrate that the system is adequate to meet the design pressure and temperature conditions.

Air under pressure is passed through test connections to check that the spray nozzles and ring headers are free of obstructions and are not clogged.

The Containment spray signal is used to trigger the actuation of valves and pumps to demonstrate the proper operation of remotely operated valves.

Each Containment spray pump runs at minimum flow, and the flow is directed through the recirculation path back to the RWST. Then the pump runs at full flow through the test line connected to the RWST. During this time, the closing of the miniflow control valves is checked. This test is performed to verify the operation of the Containment spray pumps.

6.2.2.4.3 Operational Testing

Routine testing is performed periodically to verify the operability of active CSS components.

1. Testing of valves and pumps is performed by shutting the manual valve on the Containment spray line inside the Containment, shutting the manual valve on the chemical additive supply line, and triggering a dummy actuation signal. All automatic valves and the pumps are checked for proper operation.

2. Each pump is run at full flow and the flow is directed back to the RWST.

3. The following provisions are made for periodic testing of the spray nozzles:

   a. Compressed air test connections

   b. Special facility permitting access to all ring headers

   Operators will confirm that all nozzles are free and unobstructed.

6.2.2.5 Instrumentation Requirements

CSS operation is automatically initiated by signals generated by the ESF Actuation System as described in Section 7.3. The minimum flow recirculation lines are opened when flow is less than 25%. The recirculation lines are automatically closed when 25 percent of the spray pump design flow is achieved or the Containment spray isolation valve for that pump is open or associated containment sump suction valve is opened. Flow instruments are provided in each pump discharge line. Four RWST level channels are provided and used for ECCS and CSS operation. (Refer to Section 6.3.2 for use with the ECCS.)

Level instruments provide remote indication, and high, low, low-low and empty level alarms.

A low-low [two out of four channels] level signal is provided for automatic initiation of ECCS changeover from injection mode to recirculation mode when a minimum ECCS injection volume of approximately 300,000 gallons from the minimum usable volume of approximately 440,300 gallons have been drawn by the ECCS and the CSS.

A empty level alarm is provided to annunciate the necessity to manually stop any ECCS pump still taking suction from the RWST. This alarm is initiated when approximately 30,700 gallons remain to provide pump protection above the centerline of the sparger.

Each Containment spray header riser is provided with a pressure switch to alarm in the Control Room if the level in the riser falls below the minimum level required.

Two water level instruments are provided for each Containment as shown in Figure 6.2.2-1 and 7.1-3. Both are indicated in the Control Room.

The Containment spray pump discharge pressures and flows are indicated and recorded in the Control Room.

Safety-related display instrumentation is provided as described in Table 7.5-7A for the following CSS parameters:

RWST levels

Containment spray pump flow

Containment water level

REFERENCES

1. Spray Engineering Company, Spray Analysis on Sprayco Model 1713A Nozzle by Spray Engineering Company, January 1973.

2. Pasedag, W.F., and Gallagher, J.L., Drop Size Distribution and Spray Effectiveness, WNES, Pittsburgh, Nuclear Technology, vol. 10, April 1971.

3. Parsly, L.F., Spray Tests are the Nuclear Safety Pilot Plant, in Nuclear Safety Program Annual Progress Report for Period Ending December 31, 1970, ORNL-4647, p. 82, Oak Ridge National Laboratory, 1971.

4. Parsly, L.F., Spray Program at the Nuclear Safety Pilot Plant, Nuclear Technology, vol. 10, p.472, 1971.

5. NUREG-0797, SSER No. 9 Related to the Operation of CPSES Units 1 and 2, Appendix "L", dated March 1985.

6. NRC Generic Letter 2004-02, “Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-water Reactors”

7. NEI-04-07, “Pressurized Water Reactor Sump Performance Evaluation Methodology,” Revision 0, dated December 2004.

8. TXX-05162 dated September 1, 2005, Response to Requested Information Part 2 of NRC Generic Letter 2004-2, “Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-water Reactors”

9. TXX-08033 dated February 29, 2008, Supplement to Response to NRC Generic Letter (GL) 2004-02, “Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-water Reactors”

6.2.3 SECONDARY CONTAINMENT FUNCTIONAL DESIGN

The CPNPP does not utilize a secondary Containment.

6.2.4 CONTAINMENT ISOLATION SYSTEM

The design objective of the Containment Isolation System is to allow the normal or emergency passage of fluids through the Containment boundary while preserving the ability of the boundary to limit the escape of fission products from postulated accidents.

The Containment Isolation System is designed to monitor the development of gross leakages in the Containment and to limit radioactive emission from the Containment during normal operation and in the event of loss-of-coolant accident (LOCA). All Containment Building piping penetrations are considered potential paths for the escape of radioactivity and are equipped with isolation barriers located as close to the Containment as practical. All piping penetrating the Containment and all Containment isolation barriers are rated to withstand pressures consistent with the Containment design and to operate in normal as well as postulated accident environments.

6.2.4.1 Design Bases

6.2.4.1.1 Governing Conditions

Containment isolation is mandatory in the event of a LOCA. Containment isolation is not required but could occur as a result of a main steam or feedwater line rupture inside the Containment. The system isolates the Containment to prevent or limit the escape of fission products that may result from postulated accidents. Chapter 7 describes containment isolation and other ESF actuation signals which isolate the steam generators to prevent excessive cooldown of the Reactor Coolant System (RCS) or overpressurization of the Containment.

The Containment leakage test program is described in Subsection 6.2.6. RCS leak detection is described in Section 5.2.5. Gross leakage inside the Containment is detected by the Containment air particulate monitor, radioactive gas monitor, and specific humidity monitor. Further indications of such leakage are an increased frequency of operation of the Containment sump pumps and an increase in demand for reactor coolant makeup water. Each of the above actuates Control Room alarms. In addition, the Containment air radiation monitors are provided to actuate Containment ventilation isolation valves upon sensing high levels of radiation. Refer to Table 11.5-1; the Containment isolation actuation logic diagram is presented in Figure 7.2-1. Leakage outside Containment is detected by accident monitoring instrumentation as described in Section 7.5.

6.2.4.1.2 Isolation Criteria - Fluid Systems Penetrating the Containment

In the event of a LOCA the Containment Isolation System is designed to minimize the leakage of radioactive materials through fluid lines penetrating the Containment to a low enough rate to prevent the radioactivity level from exceeding the boundary doses specified in 10 CFR Part 100.

The requirements of 10 CFR Part 50, Appendix A, General Design Criteria (GDC) 54, 55, 56, and 57, are followed with respect to the piping systems and to the number and location of independent isolation valves provided for fluid lines penetrating the Containment. Section 3.1, Conformance with NRC General Design Criteria, discusses compliance with the GDC.

All Containment piping penetrations are located in radiation controlled areas of the Auxiliary, Fuel and Safeguards buildings which are monitored for Containment leakage after a LOCA as described in Section 7.5. This is consistent with GDC-54 requirements for leak detection.

The three types of fluid lines that penetrate the Containment wall and require isolation valves are as follows:

1. Type A - Lines which form part of the reactor coolant pressure boundary (RCPB); Section 5.4.3.2 of ANSI N18.2-1973, Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants, is followed to define the limits of the RCPB.

2. Type B - Lines which connect directly with the Containment atmosphere.

3. Type C - Lines which are part of a closed system, i.e., lines that are neither part of the RCPB nor connected to the Containment atmosphere

GDC 55 is applied to Type A penetrations; except as described in Section 6.2.4.1.3, below, these penetrations are provided with one of the following isolation schemes:

1. One locked-closed isolation valve inside and one locked-closed isolation valve outside the Containment

2. One automatic isolation valve inside and one locked-closed isolation valve outside the Containment

3. One locked-closed isolation valve inside and one automatic isolation valve outside the Containment; a simple check valve is not used as the automatic isolation valve outside the Containment.

4. One automatic isolation valve inside and one automatic isolation valve outside the Containment; a simple check valve is not used as the automatic isolation valve outside the Containment.

GDC 56 is applied to Type B penetrations; these penetrations are provided with isolation schemes identical to those set forth for Type A penetrations as well as the following additional isolation schemes:

1. One blind flange inside Containment and one locked-closed isolation valve outside the Containment.

2. One blind flange inside Containment and one blind flange outside Containment.

Penetrations which are required to be closed during accident conditions are defined as GDC-55 and GDC-56 lines provided with containment automatic isolation valves which receive a containment isolation signal (Phase A, Phase B, or Containment Ventilation Isolation) or locked closed valves, blind flanges, or deactivated automatic valves secured in their position in accordance with Technical Specifications.

GDC 57 is applied to Type C penetrations; these penetrations are provided with at least one Containment isolation valve which is automatic, locked-closed, or capable of remote manual

operation. These valves are located outside the Containment and as close to it as practicable; a simple check valve is not used as the automatic isolation valve.

6.2.4.1.3 Special Containment Isolation Provisions

1. Remote Manual Operation of Isolation Valves in Safeguard Lines

Valves in lines which are required to perform a safeguard function following an accident must be opened or must remain open for the Safeguard System to operate. Automatic closing of these valves would defeat their intended purpose; therefore, these valves are designed to be operated manually from the Control Room. Lines which fall into this category include low head safety injection lines (Figure 6.2.4-1, Valve Arrangement 8), high head safety injection lines (Figure 6.2.4-1, Valve Arrangement 9, 33 and 46), Containment spray lines (Figure 6.2.4-1, Valve Arrangement 25), hydrogen purge lines (Figure 6.2.4-1, Valve Arrangement 20 and 21), Auxiliary Feedwater Lines (Figure 6.2.4-1, Valve Arrangement 36) and Main Steam Supply to the Auxiliary Feedwater Pump Turbine (Figure 6.2.4-1, Valve Arrangement 17).

Accident monitoring instrumentation described in Section 7.5 is provided to detect leakage from lines associated with these valves.

Pressure monitoring instrumentation described in Section 6.3.5.2.6 is provided to monitor pressure within high head safety injection lines associated with these valves.

2. Containment Sump Recirculation Lines

The Containment sump recirculation lines, which supply suction to the low-head safety injection (RHR) pumps, and the Containment spray pumps (Figure 6.2.4-1, Valve Arrangement 2) are each provided with a single remote-manual gate valve outside the Containment. This valve is enclosed in a valve isolation tank (Figure 6.2.2-3) and the piping from the sump to the valve is enclosed in a concentric guard pipe.

The guard pipe and valve isolation tank are not considered part of the barrier between Containment and external environment and are not tested at Containment design conditions. The reason for this is that these moderate energy lines are designed to meet the requirements of Branch Technical Position MEB 3-1 (SRP 3.6.2) with stress levels less than 0.4 ($1.2S_h + S_a$). The penetrations are designed and fabricated per ASME Section III CL2 and MC (Article NE1000) Summer '76.

The valves and isolation tanks are located in the safeguard building which are served by the ESF emergency filtration system. System arrangement also provides for valve leakage control. Valve stem leakage is piped and routed via the valve stem leakoff connections to the safeguards building sumps and then to the Floor Drain Tank No. 1. Valve bonnet leakage will be collected at the bottom of the tanks which are equipped with normally closed drain connections. These are also piped and routed via the safeguard building sumps to Floor Drain Tank No. 1. Each tank is also provided with level switches and alarms which will alert the operator in the event of significant liquid accumulation.

The isolation valves are equipped with tapered stems above the gate to provide a seating surface in the backseat position to provide additional leakage control while the valve is in an open position.

The isolation valves are also equipped with relief valves and piping from the bonnet chamber to the outlet nozzle. The relief valves prevent pressure build-up in the bonnet chamber which could result in pressure locking of the valves.

3. Relief Valves Inside Containment

The RHR suction line (Figure 6.2.4-1, Valve Arrangement 11) and component cooling water supply line to the excess letdown and reactor coolant drain tank heat exchanger are all equipped with relief valves inside the reactor Containment and form part of the Containment boundary. Containment atmosphere can impinge only on the discharge side of these valves which are held closed by spring pressure. When these valves operate, discharge is into the Containment.

Relief valve set pressure are verified by periodic bench tests. Isolation valves outside the Containment, with the exception of the RHR suction line discussed in Subsection 6.2.4.1.3, Item 5 which are inside Containment, act as redundant Containment barriers.

4. Seal Injection Lines

The seal injection lines (Figure 6.2.4-1, Valve Arrangement 15) allow flow from the charging pumps to the main seals on the reactor coolant pumps in order to provide cooling to the seals and shafts. Due to the sensitive nature of the seals, seal injection flow should be maintained when the Reactor Coolant System is not completely depressurized or when the Reactor Coolant System inventory is moving through the seal package. The charging pumps can also provide high pressure inflow following an accident. Therefore, no automatic trip valves are required for these lines; instead, a remote manual isolation valve is furnished which can be closed when the charging pumps have completed their safeguard function.

5. Residual Heat Removal System Suction Lines

Each line from the RCS hot legs to the RHR pump suction lines contains two remote-manual, motor-operated valves which are closed during normal plant operation. These RHR isolation valves are interlocked and controlled as described in Section 7.6.2 as shown in Figure 6.2.4-1, Valve Arrangement 11. The valves are interlocked so that they cannot be opened when the RCS pressure is greater than the design pressure of the RHR System. The valves closer to the RCS are interlocked with one pressure transmitter while the valves closer to containment are interlocked with a separate transmitter. The valve which is located closer to the RCS inside the missile barrier is not considered a containment isolation valve. The second valve defines the limit of the RCPB. This valve also provides the Containment isolation barrier inside the Containment, and is considered to be locked closed. Both these valves are located inside the Containment.

The RHR hot legs suction lines are connected to the safety injection (low head) Containment recirculation lines, which are filled with sump fluid after a LOCA. At least

one of these recirculation lines is in operation during the safety injection recirculation phase. It is unnecessary to provide an isolation valve outside the Containment in the RHR hot legs suction lines, since the single failure criterion is satisfied as follows:

If a leak occurs in the recirculation system outside the Containment, the sump valve is closed to prevent loss of sump water and the closed valve in the RHR suction line prevents any Containment atmosphere from entering the system outside the Containment.

If a leak occurs in the line upstream of the isolation valve (towards the reactor coolant system) the leakage will be stopped by the closed isolation valve.

If a leak occurs in the short length of pipe between the valve inside the Containment and the Containment, any Containment atmosphere will get only as far as the fluid-filled system. Since this system is filled with sump water, no gas can escape to the outside. The fluid in the RHR suction line drops to approximately the level of fluid in the sump and any Containment atmosphere which does leak into the line is contained in this length of closed piping. In order to minimize the length of pipe between the Containment wall and the first RHR isolation valve in each RHR suction line, this valve is located within 10 linear pipe feet from the Containment wall.

Another closed valve in the line would do nothing except somewhat decrease the length of pipe outside the Containment which would be exposed to Containment atmosphere following a leak. It is possible that a valve in this section of pipe would increase the probability of leakage of gas through the stem packing and cannot be considered as tight as a clean length of pipe. No single failure of any active or passive component anywhere in the present system can cause any release of Containment atmosphere to the outside. Any additional valves would complicate normal RHR operation and are unnecessary for Containment isolation.

This arrangement meets GDC 55 on the "other defined basis" criteria in that system reliability is enhanced by a single valve and there is at least a single mechanical barrier after a single active failure.

6. Leak Rate Test and Maintenance Connections (Figure 6.2.4-1, Valve Arrangements 31 and 38)

The leak rate test and maintenance connections are each equipped with a bolted blind flange with locked closed valves outside the Containment, or a bolted blind flange both inside and outside the Containment. The arrangement provided satisfies the functional requirement of GDC 56 by providing redundant isolation barriers.

7. Turbine Driven Auxiliary Feedwater (TDAFW) Pump Steam Supply and MSIV Bypass Valves (Figure 6.2.4-1, Valve Arrangement 17)

The warm-up bypass valves around the steam supply valves in the TDAFW pump steam supply lines (loop 1 & 4 only, see Figure 6.2.4-1 Sheet 5 of 10) are normally locked closed. The bypass warm-up valves are not required during an emergency cold start of the TDAFW pump.

Similarly, the manual bypass valves around the Main Steam Isolation Valves (MSIVs) are normally locked closed, and may be opened during plant startup, per Technical Specification Bases requirements, to warm up the system piping downstream of the MSIVs.

8. Local Vent, Drain and Test Connection Valves

To ensure that Containment integrity is maintained, local vent, drain, and test connection valves within the penetration boundary are locked closed and are under administrative control. See Section 6.2.6 for leak testing requirements.

The penetration boundary is defined as that portion of a GDC 55, 56 or 57 line:

a. Between containment isolation valves for normal two containment isolation valve GDC 55 or 56 lines (i.e., one valve inside and one valve outside containment).

b. Between the containment and the containment isolation valve outside containment for GDC 57 lines.

c. Between the containment isolation valve and the containment for single containment isolation valve GDC 55 or GD 56 lines (i.e., those penetrations for which special containment isolation provisions have been provided in FSAR Section 6.2.4.1.3).

9. Thermal Relief Valves (Figure 6.2.4-1, Valve Arrangements 1, 4, 5, 6, 22, 25, 26, 27, 28, 29, 30).

Thermal relief valves are provided for those penetrations which may contain stagnant fluid between closed penetration isolation valves and may be subject to external heat sources after the fluid is isolated. The valves relieve potential pressure increases in the fluid due to the heating process.

Relief valves function as Containment isolation valves, and the set pressures are greater than 1.5 times the Containment design pressure.

10. Airlock equalization valves (Figure 6.2.4-1, Valve Arrangements 41, 42 and 45)

The Unit 1 personnel hydraulically operated airlock equalization valves in valve arrangement 41 are mechanically interlocked, the Unit 1 & 2 emergency airlock equalization valves in valve arrangement 42 are mechanically interlocked, and the Unit 2 personnel hydraulically operated airlock equalization valves in valve arrangement 45 are electrically interlocked, so that only one at a time can be open. These valves are the normal equalization valves and are controlled by the airlock door operating mechanisms so that they are closed except when opening the associated door. This ensures one containment boundary is closed at all times when containment integrity is required.

Power to the hydraulic pump for these hydraulically operated valves is tripped by a safety injection signal to ensure that no failure in the non-class 1E control circuits or a spurious signal can cause the valves to open coincident with a LOCA. This satisfies the requirements of 10CFR50.49 and BTP ICSB-18.

The personnel airlock hydraulic units are supplying hydraulic power for containment airlock operation fed from non-safety related Train C power via MCC 1, 2EB1-2. In order to preclude post accident environmental conditions inside containment from causing spurious opening of the airlock doors/equalization valves, the power supply is tripped via an SI signal from both Trains. The Train A trip is accomplished by tripping the Class 1E feeder breaker to MCC 1, 2EB1-2 the Train A 480V switchgear 1, 2EB1. The Train B trip is accomplished by tripping Class 1E Train B circuit breaker CP1, CP2-BSDSEB-01 in the feeder circuit of the hydraulic unit fed from MCC 1, 2EB1-2.

The feeder circuit cables inside the personnel airlock feeder circuit control panel CP1, CP2-BSCPEB-01 are trained to preclude a short between the breaker line and load side cables. The non-Class 1E cables used in the hydraulic pump circuit cannot fail to override the safety function of opening the breaker because the cables can only short, open or fault to ground. In all such cases, power to the hydraulic pumps is terminated thus supporting the safety function. Similarly, non-Class 1E motor failure (i.e. short circuit, open circuit and short to ground) removes the motive power from the hydraulic pump thereby supporting the safety function. Therefore, tripping the power to the hydraulic pumps following an accident resulting in a safety injection signal meets the redundancy requirements of 1EEE 279.

The Unit 1 and Unit 2 personnel airlock manual equalization valves in valve arrangements 41 and 45, respectively, perform the same functions as those above except they are normally locked closed and are provided in the event the normal equalization valves are not available to relieve differential pressure across a door. They are administratively controlled to ensure one containment boundary is intact at all times when containment integrity is required.

This arrangement meets GDC-56 since redundant isolation barriers are provided and the isolation function is maintained assuming any single active or passive failure.

11. Airlock hydraulic system valves (Figure 6.2.4-1, Valve Arrangements 40 and 44).

The Unit 1 hydraulic system valves in valve arrangement 40 are locked closed except during ingress and egress as allowed by Technical Specifications. The valves must be opened for normal operation of the personnel airlock operating mechanism and interlocks. The inboard portion of the hydraulic system meets the requirements of NUREG-0800, Section 6.2.4, II.6, paragraph o, for closed systems inside Containment.

This arrangement meets GDC-57 since redundant isolation barriers are provided and the isolation function is maintained assuming any single active or passive failure.

The Unit 2 hydraulic system valves in valve arrangement 44 are locked closed. These valves are only opened under administrative controls when it becomes necessary to use the hand pump to unlatch the doors.

This arrangement meets GDC-56 since redundant isolation barriers are provided and isolation function is maintained assuming any single active or passive failure.

12. Airlock Instrumentation (pressure gauges)

The pressure gauges on the airlocks are classified as Nuclear Safety Related, Seismic Category I because they form part of the containment isolation boundary and isolation valves may not be accessible post-accident.

6.2.4.1.4 Isolation Criteria - Fluid Instrument Lines Penetrating the Containment

Instrument lines penetrating the Containment are designed in accordance with NRC Regulatory Guide 1.11.

There are four instrument lines which penetrate the Containment that are required to remain functional following a LOCA or steam line break. These lines sense the pressure of the Containment atmosphere and transmit this pressure to instruments outside the Containment.

Signals derived from these instruments initiate the safety injection, Containment isolation and Containment spray. Therefore, it is essential that these lines remain open following an accident. Isolation is provided by means of sealed bellows connected to a fluid-filled tube. This tubing, along with the transmitter and bellows, is conservatively designed and subject to strict quality control and regular inspections to assure integrity. The arrangement consists of a double isolation barrier. If the instrument line breaks outside the Containment, leakage of the Containment atmosphere is prevented by virtue of the sealed bellows. If the instrument line breaks inside the Containment, leakage is prevented by a leaktight diaphragm installed in the pressure instrument which is designed to withstand the full Containment design pressure.

6.2.4.1.5 Design Requirements for Containment Isolation Barriers

Quality standards and seismic design classification of the Containment Isolation barriers follow the recommendations of NRC Regulatory Guides 1.26, Rev. 3 and 1.29, Rev. 2, respectively. The Containment Isolation barriers are designed to seismic Category I standards, as well as temperature, pressure, humidity, and radiation conditions which exceed those expected in the event of a design basis accident (DBA).

Analyses are performed to demonstrate the integrity of the isolation valves and the connecting piping under the application of dynamic forces which would result from inadvertent closure of a valve during operating conditions (e.g., closure of a steam line isolation valve under full steaming rate). These analyses examine the pressure transients which develop in such situations. The forces and stresses resulting from these pressure transients are calculated, and displacements and support reactions are determined. As a result of these calculations, the location of support restraints is established and assurance is provided that the isolation valve pipe stresses are within allowable limits.

The equipment is designed to assure the operability of Containment Isolation System components following a DBA and during normal plant operating conditions. A detailed description of seismic qualification testing and analysis performed on safety-related mechanical equipment to assure operability during and after a postulated earthquake is given in Section 3.9.2.2. Section 3.11 discusses the environmental conditions considered in the design of the Containment Isolation System. That section also includes a discussion of the tests and analyses conducted to assure the adequacy of component performance under the specified environmental conditions.

The closed systems used as isolation barriers inside and outside the Containment satisfy the following design requirements:

1. The systems do not communicate with either the RCS or the Containment atmosphere.

2. The systems are protected against missiles and pipe whip.

3. The systems are designated seismic Category I.

4. The systems are classified ANS Safety Class 2.

5. The systems are designed to withstand temperature at least equal to the Containment design temperature.

6. The systems are designed to withstand the external pressure from the Containment structural acceptance test.

7. The systems are designed to withstand the loss-of-coolant accident transient and environmental conditions.

The valve types used for Containment isolation services are designs which have minimum leakage; essentially no leakage is anticipated through the Containment isolation valves when in the closed position.

The design pressure of piping and components within the isolation boundaries are equal to, or greater than, the design pressure of the Containment structure. Process piping, valves, and Containment penetrations are designed, constructed, and installed in accordance with the requirements of ASME B&PV Code, Section III, Code Class MC and Class 2. The Process Sampling System tubing, fittings, valves, and supports are designed, constructed, and installed in accordance with the requirements as described in FSAR Table 17A-1, Items 8 and 32. The Unit 1 Personnel Airlock Hydraulic System is designed in accordance with the requirements as described in FSAR Table 17A-1, Item 8.

6.2.4.2 System Design

A schematic diagram of the various isolation valving applications, indicating the locations with respect to the Containment barriers of all isolation valves and fluid systems penetrating the Containment wall, is shown in Figure 6.2.4-1.

Tables 6.2.4-1, 2 and 3 summarize the types of isolation valves and isolation schemes provided for the Containment Isolation System. For completeness and use with Section 6.2.6, these Tables and Tables 6.2.4-4 and 6.2.4-6 also include all Containment mechanical penetrations and have corresponding item numbers for all five Tables for ease of cross reference. See Section 6.2.6 for Containment Leakage Testing.

These tables contain the following information:

1. Containment penetration number

2. Applicable GDC or NRC Regulatory Guide

3. System name
4. Fluid contained
5. Line size
6. Engineered safety feature system (yes or no)
7. Arrangement type
8. Isolation valve number
9. Location of valve (inside or outside the Containment)
10. Type of leakage test (A, B or C)
11. Length of pipe from Containment to outermost isolation valve
12. Valve type and operator
13. Primary mode of valve actuation
14. Secondary mode of valve actuation
15. Normal valve position
16. Shutdown valve position
17. Postaccident valve position
18. Power failure valve position
19. Containment isolation signals
20. Valve closure time
21. Power source

The Containment Isolation System is automatically actuated by signals developed by the engineered safety features actuation system described in Section 7.3.1.1.4. (See Tables 7.3-1, 7.3-2, and 7.3-3, and Figure 7.2-1).

The Containment Isolation System is designed in accordance with 10 CFR Part 50, Appendix A, GDC 54, 55, 56, 57 requirements discussed in Subsection 6.2.4.1.2.

Instrument lines penetrating the Containment are designed in accordance with NRC Regulatory Guide 1.11 as described in Subsection 6.2.4.1.4.

A detailed discussion of missile protection can be found in Section 3.5. The design features and measures against jet forces and pipe whip are described in Section 3.6, and the seismic design bases for the safety-related systems are provided in Section 3.7.

In case of loss of control voltage to the associated solenoid valve, or in case of loss of air, the air-operated Containment isolation valves move to the position of greatest safety. Motor-operated Containment isolation valves fail in the as is position. Emergency power from the standby diesel generators is provided to the AC valves to ensure system operation in the event of a loss of offsite power.

All Containment isolation valves which receive signals to close from Containment isolation phase A, Containment isolation phase B, steamline isolation or feedwater isolation have valve closure times as fast as practical, consistent with the type of valves and valve operators, with consideration given to water hammer effects. Those lines which provide a direct connection from the Containment atmosphere to the environment are equipped with isolation valves having closing times of five seconds or less or are locked closed. Valve closure time for each valve is shown in Table 6.2.4-3. To ensure operability, the Containment Isolation System is designed to meet the single failure criteria with no loss of function.

The possibility of debris becoming entrained in escaping fluid and preventing tight closure of an isolation valve is of concern only for penetrations which are open to the Containment atmosphere during power operation. The Containment pressure relief line is the only penetration which falls in this category. The following provisions are made to ensure that debris does not become entrained in escaping fluid and prevent tight closing of the isolation valves in this line:

1. Pipe provided for this function is separate from other duct systems inside of the Containment and is qualified to seismic Category I by analysis; no registers or other potential sources of debris are used in this ductwork.

2. The pipe is routed to a clear area inside Containment as close to the penetration as possible; the clear area is free of potential sources of debris such as piping insulation, and so forth.

3. A debris screen covered by a flow restriction orifice plate is provided as described in Section 9.4A.

4. The isolation valves are fast closing valves which close in less than three seconds.

The redundancy requirement is satisfied by having two isolation barriers in series, one on each side of Type A and Type B penetrations. Reliability is assured by conducting periodic tests to check the operability of the isolation valves, actuators, and controls. Furthermore, a fail-safe feature is incorporated into air- operated and solenoid-operated isolation valve design, so that in the event of actuating power loss, the valve assumes the position that ensures safety.

The power operated isolation valves may be operated manually from the Control Room to provide a secondary means of actuation. To confirm performance capabilities, i.e., closing time and valve status (open or closed), indicator lights are checked and observed during the periodic testing.

The primary and secondary modes of actuation are shown in Table 6.2.4-2.

As shown in the Figure 6.2.4-1, penetrations which require leakage testing are provided with appropriate test connections.

6.2.4.3 Design Evaluation

The design of the Containment Isolation System meets the requirements for system integrity, response, operation, and reliability. Isolation valve and piping design and their location ensure Containment integrity for any postulated single failure.

Regular functional testing of the Containment Isolation System during shutdown periods assures operability of all isolation valves. Leakage rate testing during the same periods ensures that the leakage through isolation valves and piping penetrations does not exceed values commensurate with offsite radiation doses under accident conditions, given in the Technical Specification. The use of double isolation barriers ensures that no single failure of any active or passive component renders the Containment Isolation System either partially or wholly inoperable. Open or closed isolation valve status during normal plant operation is regularly checked and controlled, particularly with regard to manually-operated isolation valves. In addition, automatic isolation valves, whether actuated remote-manually or by isolation signals, are designed to assume a fail safe position. These are tabulated in Tables 6.2.4-1, 2 and 3.

No system is provided for continuous leaktightness monitoring. However, the use of double isolation barriers, periodic testing, administrative control of manual isolation valves, and surveillance of automatic isolation valves ensure that the Containment Isolation System performs its intended function. Radiation monitors, valve isolation tank level instrumentation, and Safeguards Building sump instrumentation provide post-accident leak detection in accordance with GDC-54.

All system paths penetrating the Containment wall are evaluated on the basis of their function at the time of an accident. Because some system piping penetrating the Containment performs more than one function, each system path is evaluated. Each system path has a unique Containment isolation valving arrangement as identified in Table 6.2.4-1. The system paths have been classified either as essential or non-essential.

1. Essential System Paths

   A system is designated as essential if:

   a. it is required to mitigate an accident (as ESF systems), or,

   b. unavailability could increase the magnitude of the accident.

2. Non-Essential System Paths

   A system is designated non-essential if it is not classified as essential. These systems are automatically isolated from the Containment during Containment isolation, or their lines are closed during normal operation and kept closed during an accident.

The purpose of the above selection is to identify essential systems which allow an emergency path of fluids through the Containment boundary and ensure integrity of the Containment boundary during an accident.

Table 6.2.4-6 lists all penetrations comprising the Containment isolation system together with fluid system path classifications, normal operating function and post-accident function of the Containment isolation barriers (i.e., Containment isolation valves) assuming a "P" signal has occurred.

6.2.4.4 Tests and Inspections

A rigorous program of tests and inspections is performed in accordance with 10 CFR Part 50, Appendix J, Option B, to ensure Containment Isolation System pressure integrity, leakage rate, and reliability of operation. Subsection 6.2.6 gives a detailed description. These tests ensure that the leakages from the Containment Isolation System are held within allowable Appendix J, Option B leakage rate limits. Furthermore, these tests verify the operability of the Containment isolation valving. Detailed test procedures utilized and results of tests performed are provided following completion of the tests.

Table 6.2.4-2 list the isolation valves provided for each penetration and indicates the direction in which the isolation valves will be tested. The testing arrangement for containment isolation valves will be controlled via administrative procedures and as described in FSAR Section 6.2.4 and 6.2.6.

All containment penetrations that utilize expansion bellows can be tested at P_a. Table 6.2.4-2 lists all the containment penetrations which are part of fluid system process and instrumentation piping and shows the type of local leakage testing for each penetration. Typical electrical penetration assembly is shown in Figure 3.8-8. List of all electrical penetration assemblies is shown on Figure 8.3-16. Testing of electrical penetration assemblies is described in Section 6.2.6.

Type C tests are performed on Containment isolation valves as indicated in Table 6.2.4-2. Specific exemptions from Type C testing are provided as footnotes to the table. In general these justifications include but are not limited to:

- closed systems meeting the requirements of NUREG-0800 Section 6.2.4, II.6 paragraph e and o.

- valves in systems which are inservice post accident at a pressure in excess of containment design pressure.

- valves in systems which are water filled for a period of 30 days following an accident.

Figure 6.2.4-1 shows the arrangement of test connections and test vent which permit the isolation valves to be leak tested. During testing the test vent (TV) connection is open and the pressure is applied through the test connection (TC). Test gas is applied at each test connection to establish a test volume in the piping so that the valve is exposed to gas at Containment calculated peak internal pressure. Equipment is laid out in order to minimize the size of the test volume. When necessary, test vents are supplied to ensure that the side of the valve opposite to the test gas is at ambient pressure during the test. Valves are tested in the direction of leakage from the Containment, i.e., from the center of the Containment outwards, with the following exceptions:

1. In valve arrangements 18, 19, 20, and 21 of Figure 6.2.4-1, the butterfly valves inside the Containment are tested towards the center of the Containment. Butterfly valve disc leakage is the same in either direction due to the symmetrical design of the valve.

2. In valve arrangement 22 of Figure 6.2.4-1, the diaphragm valve inside Containment will be tested toward the center of the Containment. Diaphragm valve leakage is the same in either direction due to the symmetrical design of the valve.

3. In valve arrangements 41 and 42 of Figure 6.2.4-1, the ball valves on the inboard side of the personnel and emergency airlocks are tested toward the center of the Containment. Ball valve leakage is the same in either direction due to the symmetrical design of the valve.

4. In valve arrangement 45, the manual spring closed valves are tested as part of the barrel test and the two valves on the containment side are tested in the direction away from the reactor due to the valves being unsymmetrical. Under DBA conditions, all of these manual spring closed valves are oriented in the direction which results in increasing seating force (i.e. DBA pressure loads the discharge side). Therefore, leak testing as part of the barrel test is conservative.

Containment isolation valve leakage rates are evaluated by methods discussed in Section 6.2.6.3.

Environmental qualification tests performed on the Containment Isolation System components are discussed in Section 3.11.

6.2.5 COMBUSTIBLE GAS CONTROL IN CONTAINMENT

Following a DBA, hydrogen gas may be generated inside the Containment by reactions such as zirconium metal with water, corrosion of materials of construction, exposure of the organic cable materials to radiation and radiolysis of aqueous solution in the core and sump. In addition a small amount of methane is generated by the irradiation of the cables as discussed, in Section 6.1B.2. The following section is presented to describe the design of the Combustible Gas Control System.

6.2.5.1 Design Bases

6.2.5.1.1 Generation, Accumulation, and Mixing of Combustible Gases

1. A combustible mixture can be formed when hydrogen gas concentration in the Containment atmosphere is greater than four volume percent (v/o).

2. A volume of hydrogen is generated by radiolysis in the core and the sump and is released in the compartment where the LOCA occurred and in the Containment sump where the coolant is collected.

   All subcompartments are provided with vents at the top and drains at the bottom. The vents provide for the release, caused by buoyancy, of any hydrogen generated within or beneath the subcompartment. The drains prevent the accumulation of water within a

subcompartment, thus preventing substantial generation of hydrogen by radiolysis within that subcompartment.

Arrangement of the subcompartments with bottom and top openings creates a stack effect. In addition to the driving forces generated by diffusion rate, the natural ventilation going through the subcompartments provides mixing and avoids hydrogen stratification. Therefore, the flow caused by the stack effect yields a hydrogen concentration within a subcompartment that does not substantially differ from the bulk Containment conditions.

3. Although operation of the containment spray effectively prevents hydrogen stratification, neither the containment spray nor the recirculation fans are required to ensure adequate mixing. Use of containment spray during post LOCA conditions would enhance natural circulation by causing a temperature gradient in addition to the driving force of falling drops.

6.2.5.1.2 Electric Hydrogen Recombiners

The Electric Hydrogen Recombiners for Unit 1 and for Unit 2 have been abandoned in place.

6.2.5.1.3 Hydrogen Purge System

The following design descriptions apply to the Hydrogen Purge System:

The Hydrogen Purge System functions to provide controlled purging of the containment atmosphere to aid in cleanup in accordance with GDC 60.

As required by GDC 41, when the system operates, it is capable of maintaining the hydrogen concentration in the Containment below the lower flammability limit following an accident.

The manually actuated Hydrogen Purge System has a process capacity of 700 cfm.

The system is required to be capable of operating with a Containment pressure range of 0 to 5.8 psig and temperature range of 50 to 160°F.

Protection is provided to preclude damage by missiles. All materials are selected to be compatible with accident and normal operating environments.

6.2.5.1.4 Containment Hydrogen Monitoring System

The Containment Hydrogen Monitoring System monitors the hydrogen partial pressure in several well-ventilated areas of the Containment Building in order to obtain typical values for hydrogen gas concentration.

The plant has two hydrogen monitoring systems. Each monitoring system consists of four (4) sensor modules and one (1) microprocessor analyzer. Of the four (4) sensor modules in each system, two (2) are located in each Containment. The microprocessor analyzer is thus shared by Units 1 and 2. The system can be operational within 90 minutes after an accident and is designed for continuous duty during normal plant operation. The hydrogen gas analyzers alarm at 3 v/o (wet) hydrogen.

The sensor modules and microprocessors are qualified to function under Seismic Category I requirements and post accident conditions as described in CPNPP FSAR Appendix 3A.

6.2.5.2 System Design

The primary means of reducing hydrogen concentration in the Containment following a LOCA is by the use of a Hydrogen Purge System which is available for use to aid in cleanup by providing controlled purging of the Containment atmosphere. A Containment Hydrogen Monitoring System is provided to sample the Containment atmosphere in various locations to determine the hydrogen concentration.

6.2.5.2.1 Electric Hydrogen Recombiners

Abandoned in place.

6.2.5.2.2 Hydrogen Purge System

The Hydrogen Purge System shown in Section 9.4 on Figure 9.4-6 is common to both units. This system is not used during normal operation but is capable of operating intermittently or continuously after an accident. The Hydrogen Purge system consists of two 700 cfm blowers for supply, inlet and outlet ductwork, and piping, isolation valves, a flow control valve, two atmospheric cleanup systems and two exhaust fans. The blowers are capable of transporting 700 cfm of the fresh, filtered air to the Containment. Air is drawn from either Containment as required, passed through a filterplenum (particulate, iodine adsorbers, HEPA filters) and discharged through the plant discharge duct. A demister and heater are used to maintain the humidity entering the filters below 70 percent. Two trains are provided (one train is required to operate), each capable of controlling the design airflow of 700 cfm when the containment is less than 5.8 psig.

The Hydrogen Purge System is manually operated and is isolated from the Containment by normally closed valves. Mixing of the Containment atmosphere is by natural convection.

Any radioactivity discharged is measured by the plant vent stack monitoring system.

The expected efficiencies of the filters are in accordance with NRC Regulatory Guide 1.140.

6.2.5.2.3 Containment Hydrogen Monitoring System

The hydrogen concentration in each Containment is monitored by four (4) sensors located on four (4) different elevations of the containment. Two (2) sensors from each Containment are coupled to one of the two hydrogen analyzer microprocessors located in the control room. Each microprocessor is supplied from a safety-related uninterrupted power supply train. Thus, two independent analysis trains, each monitoring two points inside each Containment, are provided for measurement.

The analyzers continuously monitor the hydrogen content of the Containment atmosphere during normal plant operation and will be operational within 90 minutes following a LOCA. This monitoring system does not rely on the hydrogen recombiner installation or operation.

The analyzer system meets with the following requirements:

Sensitivity	0.1 percent hydrogen by volume
Accuracy	±2.0 percent of full scale
Range	0-10 percent hydrogen by volume
Calibration	Fully automatic sequencing for feeding known gaseous mixtures to the sensor modules and adjustment

The sensor modules are of the in-Containment measurement type using an electrochemical sensor for specific measurement of hydrogen partial pressure.

Each sensor module consists of the following major components mounted on an integral rack: hydrogen sensor, calibration mechanism, calibration gas bottles, solenoid valves (calibration gas isolation), RTD temperature transducer and an electronics interface terminal box. One absolute pressure transducer is provided with each pair of sensor modules. This transducer is mounted on one of the sensor modules.

The analyzer microprocessor modules accept, process and condition the sensor output signal. The microprocessor has a digital display for the following:

- Hydrogen volume percent (wet)
- Hydrogen volume percent (dry)
- Hydrogen partial pressure
- Temperature
- Pressure

The control room operators are able to select any display for instantaneous readout. The microprocessors also have two buffered 0- 10 volt dc output signals for remote analog display of hydrogen volume percent (wet) on the Main Control Board.

The alarms from the microprocessor modules are from solid state relays and indicate the following conditions: high hydrogen concentration, power failure and system error.

The Containment Hydrogen Monitoring System is designated as IEEE Class 1E and qualified per requirements of IEEE 323-1974.

6.2.5.3 Design Evaluation

6.2.5.3.1 Hydrogen Generation

Based on the revision to 10CFR50.44 effective October 16, 2003, the calculation of hydrogen generation following LOCA is no longer needed.

6.2.5.3.2 Hydrogen Mixing

As described in Subsection 6.2.5.1.1, all subcompartments are provided with vents to aid in hydrogen mixing and to avoid high concentration pockets of hydrogen. These vents cause a stack effect which maintains the subcompartments at virtually the same hydrogen concentration as the remainder of the Containment.

This stack effect is governed by the following formula:

$$Q = 7.2A\sqrt{ht}$$

where

Q	=	air flow (ft^3/min)
A	=	area of bottom or top openings, whichever is smaller (ft^2)
h	=	height from bottom to top openings (ft)
t	=	temperature difference between the subcompartment and the bulk Containment atmosphere (F)
7.2	=	constant of proportionality, for conditions not favorable

At a minimum temperature gradient of 1°F, the number of air changes per hour is always in the range of 2 to 3.

With regard to mixing of post-LOCA hydrogen, the following aspects have been considered:

1. Mixing in the bulk Containment above operating floor at elevation of 905 ft 9 in.

   Experimental results from spray experiments conducted at Oak Ridge National Laboratories have substantiated the adequacy of the sprays to ensure mixing in the bulk Containment volume. These results apply to the Region A described in Section 6.5, Figure 6.5-2. While spray operation is a sufficient condition to ensure mixing, it is not a necessary condition. The stack effect described above would also be effective in this region under LOCA conditions, as would a thermal/buoyancy plume formed from the effluent of the break.

2. Subcompartments are enclosed between floor elevations 808 ft 0 in., 832 ft 6 in., 860 ft 0 in., and 905 ft 9 in.

   These regions are described in Section 6.5 and shown on Figure 6.5-2, where they are referenced as Region B, C, and D. To avoid accumulation of hydrogen between floors, each of them is provided with openings to permit mixing with the bulk Containment.

   Between the Region D and the other regions, the total opening is approximately 900 ft^2. Although the hottest subcompartment is the steam generator subcompartment, a temperature difference between the upper Containment and the lower floors exists as a

result of the cold water sprayed in the dome which induces natural convection. This natural convection ensures a general mixing of hydrogen in the Containment, after spray operation. If sprays are not in operation, the mixture in Region D will be entrained into the hotter steam generator compartment, or into the openings on the floor, as a result of the stack effect. A mixture descending along the liner will be colder as a result of condensation on the liner. This natural circulation loop ensures mixing even if sprays are not operating. Alternatively, conditions also can induce the formation of a thermal/ buoyancy plume which will entrain steam and gases as it rises. The plume hydrogen concentration is near the average ambient concentration at the upper containment elevations.

These three regions are partially sprayed by nozzles (see Section 6.5, Table 6.5-5) when operating containment spray during the injection and recirculation phases. In addition, the driving force of falling drops enhances air circulation.

3. Subcompartments Where LOCA Occurs

These subcompartments are the steam generator subcompartments, the connecting pipe tunnel to reactor vessel cavity, and the pressurizer subcompartment.

A large part of the hydrogen generated in the Containment is released in the subcompartment where the break occurs, as a result of radiolysis in the core.

a. Steam Generator Subcompartments

Each steam generator subcompartment is fully open at the top and provided with two main openings in the bottom (for communication with another steam generator subcompartment and personnel access). This arrangement has the following effects:

1. Coverage of the steam generator subcompartment with spray, ensuring a mixing within the subcompartment

2. Release of hydrogen through the top as a result of its low atomic weight

3. Mixing of the contents of the steam generator subcompartment with the contents of the bulk Containment through natural convection effects. A sensible energy is introduced during the long-term with the core recirculation flow in the subcompartment and provides the driving forces for mixing

b. Pressurizer Subcompartment

Hydrogen entering this subcompartment is vented through a 36-ft^2 top vent. This opening is in the vertical wall underneath the slab. Hydrogen is released above elevation 905 ft 9 in. in Region A, which is the bulk Containment volume (see Section 6.5, Figure 6.5-2).

4. Subcompartments Where There Is No LOCA

a. Pressurizer Relief Tank Subcompartment

This subcompartment has a bottom drain opening of 100 ft^2. Hydrogen released within the subcompartment and hydrogen entering the subcompartment is vented through the top vents.

b. Cubicles at Elevation 808 ft 0 in.

These cubicles are for excess letdown heat exchanger, reactor coolant drain tank and pumps, and reactor coolant drain tank heat exchanger. The Containment Building arrangement is such that the sump water will enter these cubicles and will generate hydrogen which could accumulate in the upper parts.

Consequently, all cubicles located at elevation 808 ft 0 in. are provided with a vent at their highest points to avoid local high level hydrogen concentration.

c. Reactor Cavity

Part of the fluid spilled out of the break and part of the water volume sprayed fill the reactor cavity. Hydrogen generated in the cavity by radiolysis is released through the gap around the reactor vessel and through the relief openings located in each floor (elevations 808 ft 0 in., 832 ft 6 in., and 849 ft 0 in.).

6.2.5.3.3 Electric Hydrogen Recombiners

The Electric Hydrogen Recombiners have been abandoned in place.

6.2.5.3.4 Hydrogen Purge System

The Hydrogen Purge System is capable of continually or intermittently processing a minimum of 700 cfm.

If a supply blower or exhaust fan fails, redundant fans will be able to supply or exhaust air by changing the valve and damper arrangement. Air supply and exhaust lines are arranged so as not to be rendered inoperative by accumulation of water in the line from Containment spray, condensation, or flooding.

All equipment is leaktight, and the filter housings are designed to facilitate replacement without undue exposure of personnel to radioactive sources.

The Hydrogen Purge exhaust air filtration units meet the requirements of NRC Regulatory Guide 1.140 as discussed in Appendix 1A(B).

The supply and exhaust lines are routed through different Containment penetrations. Each fan is connected to an emergency standby diesel generator bus. (Section 8.3)

The Containment isolation valves, the piping inside the Containment, and the piping between the isolation valves are ANS Safety Class 2. The exhaust equipment beyond the outboard Containment isolation valves is non-nuclear safety, seismic category II.

6.2.5.3.5 Containment Hydrogen Monitoring System

The Containment Hydrogen Monitoring System is capable of determining the hydrogen concentration at four elevations in the Containment. Four sensor modules and two microprocessors analyzers are provided to ensure that sufficient redundancy is available.

6.2.5.4 Tests and Inspections

Test programs for preoperational testing and periodic test are implemented.

1. Deleted.

2. Hydrogen Purge System

   Component qualification tests demonstrate the characteristics of materials incorporated into components (e.g., efficiency of charcoal filter).

   Component acceptance tests demonstrate the capability of the components incorporated. Fans are tested by the manufacturers to determine that their characteristic curves are within design limits.

   A post-installation test is performed to demonstrate system compliance with design requirements. During this test, fans are testing in accordance with the standards of the Air Moving and Conditioning Association (AMCA), and filters are tested in accordance with NRC Regulatory Guide 1.140 (See Appendix 1A(B)). All ductwork/piping of the Hydrogen Purge Air cleanup system are quantitatively leak tested from the outboard containment isolation valves.

   After installation the Hydrogen Purge System can be tested. The system is normally idle. Periodic tests are performed on major components to demonstrate their ability to function.

3. Containment Hydrogen Monitoring System

   The Containment Hydrogen Monitoring System is calibrated when installed and periodically recalibrated in accordance with manufacturer's instructions.

   The sensors will be automatically recalibrated using known calibration gases containing two (2) and six (6) percent hydrogen in high purity nitrogen. The calibration cycle will be automatically initiated at regular intervals by the microprocessor system, although manual initiation is also possible.

   The Containment Hydrogen Monitoring System will be field tested in accordance with Regulatory Guide 1.68, "Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors."

6.2.5.5 Instrumentation Requirements

The hydrogen monitoring system is used in determining Containment hydrogen concentration. This measurement can be taken from any of four sensor locations within the Containment. Instrumentation is provided to both monitor the hydrogen concentration in the Containment and

to monitor the Hydrogen Purge System operation. Two hydrogen indicators are provided, one mounted on the Main Control Board and the second one on the microprocessor analyzer.

The hydrogen purge supply blowers and exhaust fans are manually started from the Control Room. A humidity control heater located in the filter is interlocked with the fan to come on when the fan is started and to shut off when the fan is stopped. A thermistor is provided on the discharge side of the iodine adsorber to provide a high temperature signal to the Fire Protection Systems panel. Differential pressure switches and/or indicating switches are provided to monitor the differential pressure across the fans and exhaust filtration units. A low alarm is annunciated from the fan switch and a high alarm from the filter bank.

6.2.5.6 Materials

The materials of construction for the electric hydrogen recombiners are selected for their compatibility with the post-LOCA environment.

The major structural components are manufactured from 300-Series stainless steel. Incoloy-800 is used for the heater sheaths and Inconel-600 for other parts such as the heat duct, which operates at high temperature.

There are no radiolytic or pyrolytic decomposition products from these materials. Materials of construction for Containment Hydrogen Purge System components are listed in Table 6.2.5-6.

REFERENCES

1. 10 CFR Part 50, Appendix A, General Design Criterion 41, Containment Atmosphere Cleanup.

2. 10 CFR Part 50, Appendix A, General Design Criterion 42, Inspection of Containment Atmosphere Cleanup Systems.

3. 10 CFR Part 50, Appendix A, General Design Criterion 43, Testing of Containment Atmosphere Cleanup Systems.

4. Deleted.

5. Deleted.

6. NRC Regulatory Guide 1.22, Periodic Testing of Protection System Actuation Functions, February 1972, U.S. Nuclear Regulatory Commission.

7. NRC Regulatory Guide 1.26, Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants, Rev. 3, February 1976, U.S. Nuclear Regulatory Commission.

8. NRC Regulatory Guide 1.29, Seismic Design Classification, Rev. 2, February 1976, U.S. Nuclear Regulatory Commission.

9. ANSI N18.2, Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants, 1973.

10. Branch Technical Position APCSB 9-2, Residual Decay Energy for Light Water Reactors for Long-Term Cooling.

11. Branch Technical Position CSB 6-2, Control of Combustible Gas Concentrations In Containment Following a Loss of Coolant Accident, Nov. 24, 1975.

12. J. F. Wilson, Electric Hydrogen Recombiner for PWR Containments, WCAP-7709 (Proprietary) and WCAP-7820, Supplements 1, 2, 3, 4 and 5 (Nonproprietary).

13. TID-14844, Calculation of Distance Factors for Power and Test Reactor Sites, March 23, 1962.

14. ANSI N101.1, Efficiency Testing of Air-Cleaning Systems Containing Devices for Removal of Particles, 1972.

15. Letter from D. B. Vassallo (NRC) to C. Eicheldinger (Westinghouse) dated May 1, 1975.

16. Letter from J. Stolz (NRC) to T. M. Anderson (Westinghouse) dated June 22, 1978.

6.2.5A HYDROGEN PRODUCTION AND ACCUMULATION

This section has been deleted.

6.2.6 CONTAINMENT LEAKAGE TESTING

The Containment Building, Containment penetrations, and Containment isolation barriers are designed to permit periodic leakage rate testing as required by GDC 52, 53, and 54 of Title 10, Code of Federal Regulations, Part 50, Appendix A [2] [3] [4], in accordance with the requirements of 10 CFR Part 50, Appendix J, Option B [1]. Containment leakage tests are performed to verify that Containment leakage is maintained below the acceptable limits stated in the Technical Specifications.

The leakage testing program consists of the following types of leakage tests:

1. Type A Tests

   Type A tests are those tests, as defined in 10 CFR Part 50, Appendix J, Option B, to measure the containment system overall integrated leakage rate, conducted after the Containment System has been completed, and is ready for operation, and at a periodic interval based on the historical performance of the overall Containment System.

2. Type B Tests

   Type B tests are those tests, as defined by 10 CFR Part 50 Appendix J, Option B, which are performed to measure leakage rates across pressure retaining or leakage limiting boundaries other than valves.

3. Type C Tests

Type C tests are those tests, as defined by 10 CFR Part 50, Option B, which are performed to measure Containment isolation valve leakage rates.

6.2.6.1 Containment Integrated Leakage Rate Test (Type A Test)

The maximum allowable Containment integrated leakage rate for the Comanche Peak Nuclear Power Plant (CPNPP) is 0.10 weight percent per day at a pressure of P_a equal to the calculated peak Containment internal pressure as specified in the Technical Specifications. After completion of construction of the Containment and the installation of all mechanical, fluid, electrical, and instrumentation systems penetrating the Containment pressure boundary, a Containment structural acceptance test was performed as described in Section 3.8.1. A detailed description of the preparation and inspection of the Containment structures, which is performed prior to the Containment structural acceptance test, is given in Section 3.8.1. For Unit 1 initial Type A leakage rate test was performed at a reduced pressure P_t equal to 0.5 P_a following completion of the structural acceptance test. The reduced pressure leakage-rate test was initiated when the Containment pressure had been reduced to P_t. A peak pressure test was then performed at the calculated peak internal pressure P_a. Leakage-rate tests are performed periodically during the operating life of the plant in accordance with 10CFR50, Appendix J, Option B.

Containment integrated leakage rate tests are performed in accordance with the requirements of 10 CFR Part 50 Appendix J, Option B, ANSI/ANS-56.8-1994 “Containment System Leakage Testing Requirements,” NEI 94-01 “Industry Guideline for Implementing Performance - Based Option of 10CFR Part 50 Appendix J”, and also allowed performance of reduced duration periodic tests using the Bechtel Topical Report BN-TOP-1 criteria and methodology.

Containment System Leakage Testing Requirements. For periodic integrated tests, minimum pathway local leakage rate test corrections will be used, where applicable, for isolated penetrations.

Prior to performance of Type A leakage-rate tests, the Containment isolation valves are closed by normal operation without any adjustment. All piping assemblies are equipped with low point drains and high point vents. This will allow exposing the piping systems as applicable, including the portions which are part of the Containment isolation system, to Containment atmosphere during Containment integrated leakage rate (type A) test. Portions of some systems which penetrate the Containment and are located inside the Containment or are directly connected to the penetration outside the Containment are drained and vented during the leakage-rate test. The portion inside the Containment is vented to the Containment atmosphere and the portion outside is vented to the environment to ensure that the full Containment test air pressure is imposed on the isolation valves. The portions of the RCS constituting the reactor coolant pressure boundary (RCPB) need not be drained or vented since no portion of the RCPB penetrates the Containment. The RHR system lines and those safety injection system lines which will be filled with water and required to operate during an accident are not drained and vented during the leakage-rate test. Table 6.2.4-4 lists penetrations which are filled with water during a Containment leakage rate (Type A) test and therefore not exposed to Containment atmosphere. These fluid lines are part of systems that during post-accident recovery are operating at a pressure significantly higher than Containment pressure, or are required for safe and efficient conduct of the test, or are lines designed in accordance with NRC Regulatory Guide 1.11. Penetrations with isolation valve arrangements conforming to GDC 57

(Section 6.2.4.1.2) per Table 6.2.4-1 are not necessarily drained or vented during the Type A test and are not listed in Table 6.2.4-4. In addition, for planning and scheduling purposes or ALARA considerations, penetrations which are Type B or C test either within the previous 24 calendar months prior to the ILRT or during the ILRT outage, need not be vented or drained during the Type A test and are not necessarily listed on Table 6.2.4-4.

The Containment is pressurized to the test pressure P_a and air mass allowed to stabilize for a minimum of four hours. During this stabilization period as well as during the test, the Containment Air Recirculation and Cooling System may be operated, if required, to circulate the Containment atmosphere and provide a homogeneous mixture. Containment cooling may be provided to maintain a constant temperature. If possible, the Containment integrated leakage-rate tests are performed during periods of relatively stable weather conditions.

Upon commencement of the leakage-rate test following the period of stabilization, the following parameters are measured and recorded for the duration of the test:

1. Containment absolute pressure

2. Containment dry bulb temperature

3. Containment dew point temperature or relative humidity (to determine vapor pressure of moisture in Containment atmosphere)

Using the Mass Point method of ANSI/ANS-56.8-1994 a periodic test extends for at least 8 hours. Reduced duration periodic tests may also be performed using the Bechtel Topical Report BN-TOP-1 criteria and methodology. The temperature measurements are taken from a sufficient number of separate locations in the Containment to permit determination of a mean representative temperature. Leakage-rates are calculated using previously mentioned data and the methods from ANSI/ANS 56.8-1994 and/or BN-TOP-1. The Containment pressure is corrected for the partial pressure of water vapor.

Upon completion of the leakage-rate test the results of the test are validated by a verification test in accordance with the method outlined in ANSI N56.8-1994 and/or BN-TOP-1. This verification essentially consists of imposing a calibrated leakage on the Containment vessel in addition to existing leakages. Readings of Containment parameters are resumed and a new leakage-rate is calculated to be compared with the originally calculated leakage rate.

Acceptance criteria for the Containment integrated leakage-rate tests are as follows:

1. Preoperational Tests

   Peak pressure test leakage rate L_{am} is acceptable if it is less than 75 percent of L_a and not greater that L_d as previously defined by 10 CFR Part 50, Appendix J.

2. Periodic Tests

   The “As Left” containment integrated leakage rate is acceptable if the leakage at the 95% UCL plus all applicable additions and corrections is less than or equal to 0.75 La as specified in the Technical Specifications.

The "As Found" containment integrated leakage rate is acceptable if the leakage at the 95% UCL plus all applicable additions, corrections, and leakage improvements (from repairs/adjustments performed prior to the ILRT), is less than or equal to 1.0 L_a as specified in the Technical Specifications. For preoperational/prestart test program tests, the sum of the post repaired minimum path local leakage rate valves was added to the upper confidence limit (UCL) per ANSI 56.8-1987.

6.2.6.2 Containment Penetration Leakage Rate Test (Type B Test)

Tables 6.2.4-1, 6.2.4-2 and 6.2.4-3 list all Containment mechanical penetrations as well as the type of penetration and leakage testing method. Figure 8.3-16 lists all Containment electrical penetrations (which are Type B tested). The Containment pressure sensing instrument penetrations are not subject to Type B testing. Each Containment pressure sensing instrument constitutes a closed, liquid-filled system sealed on the inside of the Containment by a diaphragm and on the outside by the pressure transmitter; both are designed to withstand Containment pressure and temperature and postaccident environment. The sealed pressure sensing system is designed to withstand the SSE and is protected from postulated missiles as well as pipe whip and jet impingement effects resulting from postulated pipe ruptures.

The leakage-rate tests performed on the various types of penetrations are described in the following paragraphs:

1. The equipment hatch, personnel airlock, emergency airlock, and fuel transfer tube are provided with covers sealed by gaskets designed so that the space between the gasket sealing surfaces can be pressurized. The seal is tested by either pressurized air or nitrogen P_a and measuring the leakage rate.

   The hydraulic system which constitutes the personnel airlock operating mechanism (See Section 3.8.1), contains some non-metallic seals and component necessary for it to perform its design function. These materials have been environmentally qualified for post-LOCA conditions. In normal use during the opening and closing of the airlock door, these seals and components are normally pressurized to between 100 psig to 500 psig. Any leakage or failure would be readily visible at the point of Containment ingress and egress. In addition, the Unit 1 hydraulic system boundary is included in the Type A and airlock barrel tests. Therefore, no additional testing is required.

2. The fuel transfer tube penetration consists of a sleeve embedded in the Containment wall and welded to the liner through which the transfer tube passes. The sleeve is sealed to the transfer tube by two bellows expansion joints, one on each side of the penetration. Figure 6.2.6-1 shows the fuel transfer tube leak test arrangement.

   A test connection is provided so that the space between the transfer tube and the sleeve with connecting bellows can be pressurized to Pa in order to measure the leakage rate of the bellows or attachment welds.

3. The Containment recirculation sump penetrations consist of sleeves embedded in the Containment mat with the process pipe seal welded to the sleeve by a seal ring inside the Containment. The sleeve is welded to the Containment liner. Each isolation valve outside the Containment is enclosed within a valve isolation tank which is sealed to the

sleeve by a 24 inch guard pipe and to the process pipe downstream of the isolation valve by a bellows expansion joint (see Figure 6.2.2-3). The bellows, guard pipe and isolation tank assembly do not require testing as discussed in Section 6.2.4.1.3.

All other mechanical penetrations do not incorporate any expansion joints or resilient seals. They consist of either a pipe embedded in the Containment wall concrete and welded to the Containment liner or a sleeve embedded and welded to the liner with the process pipe passing through the sleeve and sealed by a flued head welded to the sleeve. These penetrations are tested by a type C test performed on the isolation valves as described in Subsection 6.2.6.3.

4. Maintenance and Containment Leakage Rate Test

Pressurization/pressure sensing penetrations consist of pipes or sleeves embedded in the Containment wall concrete, welded to the Containment liner and blind flanged shut at each end. A test connection is provided so that the space between the end flanges can be pressurized to P_a in order to measure the leakage rate.

5. Electrical penetrations are tested as follows:

The design of each electrical penetration assembly includes two static seals at pressure retaining boundary interfaces. The pressure retaining integrity of these seals is monitored by a pressure gauge located outside of the Containment. To determine leak rate of the penetration pressure system, the assembly is pressurized with dry nitrogen to a pressure equal to P_a.

The results of Containment penetration leakage-rate tests are acceptable if the combined leakage rates of all penetrations and valves subject to type B and C tests are less than or equal to 60 percent of L_a as defined by Technical Specifications.

Local test connections, vent and drain valves (TVDs) within the penetration boundary are subject to the same leak rate testing as the other containment isolation valves in the associated penetration, including all applicable leak testing exceptions (see FSAR Table 6.2.4-2 including notes). However, TVDs in the penetration boundary that are one inch or less in size, consist of a double barrier (such as capped or isolated by blind flange) and under administrative controls are not required to be leak rate tested.

6.2.6.3 Containment Isolation Valve Leakage Rate Test (Type C Test)

All Containment isolation valves are listed on Tables 6.2.4-1, 2 and 3, Part B, with applicability of Type C testing indicated for each valve or set of valves. Each valve or set of valves subject to Type C testing will be tested by pressurizing with air or nitrogen to maintain a differential pressure of at least Pa across the valve(s). Test connections and test vents are provided in the piping to facilitate Type C testing. The results of Containment isolation valve leakage rate testing are acceptable if the combined leakage rates of all penetrations and valves subject to Type B and C testing are less than or equal to 60 percent of L_a as defined by Technical Specifications.

Local test connections, vent and drain valves (TVDs) within the penetration boundary are subject to the same leak rate testing as the other containment isolation valves in the associated

penetration, including all applicable leak testing exceptions (see FSAR Table 6.2.4-2 including notes). However, TVDs in the penetration boundary that are one inch or less in size, consist of a double barrier (such as capped or isolated by blind flange), and under administrative controls are not required to be leak rate tested.

6.2.6.4 Scheduling and Reporting of Periodic Tests

1. Containment integrated leakage-rate test (Type A) are performed at least once per 48 months with possible extension to 10 yr. intervals based upon acceptable performance history as determined in accordance with NEI 94-01 and Reg. Guide 1.163, as modified by the exceptions in Technical Specification 5.5.16.a. Type A tests are only conducted while the plant is in the shutdown condition.

2. Containment penetration leakage-rate tests (Type B) are performed at 24 month intervals with possible extension up to 10 yr. intervals as determined in accordance with NEI 94-01. The personnel airlock and emergency airlock door seals are tested after opening and overall leak rate tested at 30 month intervals.

3. Containment isolation valve leakage-rate test (Type C) are performed at 24 month intervals with possible extension to 5 yr. intervals as determined in accordance with NEI 94-01 and Reg. Guide 1.163.

4. The preoperational test results are documented in accordance with the requirements of 10 CFR 50, Appendix J, Section V and periodic test results are documented in accordance with the requirements of 10 CFR Part 50, Appendix J, Option B, Section IV.

6.2.6.5 Special Testing Requirements

Any major modification or replacement of a component which is part of the primary reactor Containment performed after the preoperational leakage-rate test will be followed by a Type A, Type B, or Type C test as applicable. Testing may be deferred to the next regularly scheduled Type A test for the following repairs or modifications:

- Welds of attachments to the surface of steel pressure-retaining boundary;

- Repair cavities, the depth that does not penetrate required design steel wall by more than 10%; or

- Welds attaching to steel pressure-retaining boundary penetrations, where the nominal diameter of the welds or penetrations does not exceed one inch.

All other requirements for regularly scheduled leakage-rate tests apply to the previously mentioned special tests.

REFERENCES

1. 10 CFR Part 50, Appendix J, Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors, Option B, Performance Based Requirements.

2. 10 CFR Part 50, Appendix A, General Design Criterion 52, Capability for Containment Leakage Rate Testing.

3. 10 CFR Part 50, Appendix A, General Design Criterion 53, Provisions for Containment Testing and Inspection.

4. 10 CFR Part 50, Appendix A, General Design Criterion 54, Piping Systems Penetrating Containment.

5. ANSI N45.4-1972, Leakage-Rate Testing of Containment Structures for Nuclear Reactors, 1972.

6. ANSI/ANS 56.8-1994, Containment System Leakage Testing Requirements.

7. ANSI/ANS 56.8-1987, Containment System Leakage Testing Requirements, 1987.

8. Bechtel Topical Report BN-TOP-1, Testing Criteria for Integrated Leakage Rate Testing of Primary Containment Structures for Nuclear Power Plants, Rev. 1, November 1, 1972.

9. WCAP-8204, Westinghouse Mass and Energy Release Data for Containment Design.

10. NEDO-13418, Critical Flow of Saturated and Subcooled Water at High Pressure, Sozzi, G. L. and Sutherland, W. A.

11. Regulatory Guide 1.163, “Performance-Based Containment Leak-Test Program”, September 1995.

12. NEI 94-01, Rev. 0, Nuclear Energy Institute “Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J”, July 26, 1995.

TABLE 6.2.1-1

THIS TABLE HAS BEEN DELETED

TABLE 6.2.1-2
CONTAINMENT PEAK PRESSURE AND TEMPERATURE ANALYSIS FOR LOCA

BREAK	INITIAL CONTAINMENT CONDITIONS P/T/RH[a] (PSIA/°F/%)	SINGLE FAILURE	CONTAINMENT PEAK PRESSURE (PSIG)	TIME FOR PEAK PRESSURE (SEC)	CONTAINMENT PEAK TEMPERATURE (°F)	TIME FOR PEAK TEMPERATURE (SEC)	PRESSURE MARGIN (psi)	PRESSURE MARGIN AS A PERCENT OF PEAK PRESS (%)
DEPSG	16.2/120/15	1 CS TRAIN	43.2	74.6	263.1	24.0	6.8	15.7
DEPSG[b]	16.2/120/15	1 ESF TRAIN	47.2	3407.0	270.1	446.6	2.8	5.9
DEPSG	16.2/120/15	NONE - BLOWDOWN ONLY	41.1	22.0	261.0	21.5	8.9	21.6

a) RH = Relative Humidity

b) The limiting LOCA scenarios with respect to peak injection phase pressure and/or temperature, highest pressure or temperature at 24 hours, and highest recirculation phase temperature are reanalyzed to evaluate modifications to analysis input models.

c) The temperature and pressure profiles utilized for EQ evaluations bound the limiting temperature and pressure transients for postulated LOCA and MSLB events.

Notes:

1) CS - Containment Spray

2) ESF - Engineered Safety Features (ECCS & CSS)

TABLE 6.2.1-2A
CONTAINMENT PEAK PRESSURE AND TEMPERATURE FOR A SPECTRUM OF STEAM LINE BREAKS
(Sheet 1 of 2)

BREAK DESCRIPTION	POWER LEVEL	ASSUMED FAILURE	INITIAL CONTAINMENT CONDITIONS P/T/RH (PSIA/°F/%)	PEAK PRESSURE (PSIG)	TIME AFTER BREAK TO PEAK PRESSURE (SEC)	PRESSURE MARGIN (PSI)	PRESSURE MARGIN AS A PERCENT OF PEAK PRESS (%)	PEAK TEMPERATURE (°F)	TIME AFTER BREAK TO PEAK TEMPERATURE (SEC)
FULL DE	100.6%	MSIV	16.2/120/15	33.0	200.6	17.0	51.5	316.9	50.5
FULL DE	70%	MSIV	16.2/120/15	33.9	240.2	16.1	47.5	313.8	50.1
FULL DE	30%	MSIV	16.2/120/15	34.7	360.2	15.3	44.1	312.0	50.1
FULL DE	0%	MSIV	16.2/120/15	36.1	260.2	13.9	38.5	305.9	60.1
3 FT^2 SPLIT RUPTURE	100.6%	MSIV	16.2/120/15	34.5	200.2	15.5	44.9	324.9	40.1
5 FT^2 SPLIT RUPTURE	70%	MSIV	16.2/120/15	35.6	240.2	14.4	40.4	324.3	40.1
7 FT^2 SPLIT RUPTURE	30%	MSIV	16.2/120/15	36.9	380.2	13.1	35.5	324.1	30.1
7 FT^2 SPLIT RUPTURE	0%	MSIV	16.2/120/15	37.7	280.2	12.3	32.6	318.2	30.1
FULL DE	100.6%	1 CS TRAIN	16.2/120/15	32.7	620.2	17.3	52.9	307.1	80.2
FULL DE	70%	1 CS TRAIN	16.2/120/15	34.3	620.2	15.7	45.8	304.7	80.1
FULL DE	30%	1 CS TRAIN	16.2/120/15	36.6	620.2	13.4	36.6	303.2	90.2
FULL DE	0%	1 CS TRAIN	16.2/120/15	36.4	260.2	13.6	37.4	299.5	100.2
4.3 FT^2 DE SPLIT RUPTURE	100.6%	1 CS TRAIN	16.2/120/15	34.2	620.2	15.8	46.2	312.9	70.1
4.5 FT^2 DE SPLIT RUPTURE	70%	1 CS TRAIN	16.2/120/15	35.9	620.2	14.1	39.3	311.6	60.1

TABLE 6.2.1-2A
CONTAINMENT PEAK PRESSURE AND TEMPERATURE FOR A SPECTRUM OF STEAM LINE BREAKS
(Sheet 2 of 2)

BREAK DESCRIPTION	POWER LEVEL	ASSUMED FAILURE	INITIAL CONTAINMENT CONDITIONS P/T/RH (PSIA/°F/%)	PEAK PRESSURE (PSIG)	TIME AFTER BREAK TO PEAK PRESSURE (SEC)	PRESSURE MARGIN (PSI)	PRESSURE MARGIN AS A PERCENT OF PEAK PRESS (%)	PEAK TEMPERATURE (°F)	TIME AFTER BREAK TO PEAK TEMPERATURE (SEC)
4.7 FT^2 DE SPLIT RUPTURE	30%	1 CS TRAIN	16.2/120/15	39.0	620.2	11.0	28.2	311.1	50.2
4.7 FT^2 DE SPLIT RUPTURE	0%	1 CS TRAIN	16.2/120/15	38.3	280.2	11.7	30.5	305.3	50.1

a) The temperature and pressure profiles utilized for EQ evaluations bounds the limiting temperature and pressure transients for postualated LOCA and MSLB events.

TABLE 6.2.1-2B
THIS TABLE HAS BEEN DELETED

TABLE 6.2.1-2C
THIS TABLE HAS BEEN DELETED

Table 6.2.1-3
BLOWDOWN MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 1 of 8)

	Break Path No. 1[(a)]		Break Path No. 2[(b)]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
0	0	0	0	0
0.00109	89632.3	50304.5	43101.2	24133.7
0.101	42880	24068.4	22028.8	12321.3
0.202	48199.5	27195.4	24421	13670.9
0.301	47722.6	27093.1	24528.1	13742.5
0.402	47591.5	27220.5	23609.3	13239.3
0.501	47613.3	27462.3	22440.3	12591.8
0.601	46213.2	26893.4	21448.8	12039.1
0.701	46400.9	27237.4	20577.9	11552.6
0.802	46336.7	27420.8	19947.1	11201
0.902	45804.7	27306.9	19525.8	10968.6
1	44835.1	26913	19290.9	10839.3
1.1	43774.2	26453.9	19147.6	10760.6
1.2	42801.9	26033.7	19072.5	10719.5
1.3	41931.2	25664.8	19027.6	10694.8
1.4	41153.8	25343.4	18999.7	10679.2
1.5	40429.1	25044.6	18987.4	10672.2
1.6	39712.4	24748.3	18991.6	10674.6
1.7	38980.9	24445.2	19005.6	10682.5
1.8	38215.6	24128.2	19007.6	10683.7
1.9	37384.5	23777.7	18987.2	10672.2

Table 6.2.1-3
BLOWDOWN MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 2 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
2	36449.4	23372.9	18963.7	10659
2.1	35428	22919.8	18932.2	10641.6
2.2	34362.5	22440.5	18862.9	10602.8
2.3	33172.8	21879.2	18746.7	10537.8
2.4	31999.5	21316.3	18589.2	10449.4
2.5	30798.8	20721	18352.6	10315.9
2.6	29628.7	20132.8	17928.3	10077.6
2.7	28070	19251.1	17725.3	9965
2.8	25153.3	17394.1	17512.9	9846.5
2.9	23235.5	16222.5	17292.3	9723.3
3	22185.5	15633.8	17078.9	9604.4
3.1	20987.2	14886.5	16877	9492.2
3.2	19988.7	14255.3	16679.5	9382.5
3.3	19199.2	13756.7	16498.9	9282.4
3.4	18473.2	13288.2	16329.9	9188.8
3.5	17805.8	12852.1	16162.2	9095.9
3.6	17202.8	12456.2	16010.6	9012.2
3.7	16680.5	12112.8	15874.5	8937.1
3.8	16226	11812.7	15741.9	8864
3.9	15815.7	11538.8	15607	8789.4
4	15448	11290.9	15480.3	8719.6

Table 6.2.1-3
BLOWDOWN MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 3 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
4.2	14867.1	10894.8	15253.6	8594.7
4.4	14400	10564.4	15006.6	8458.1
4.6	14037.5	10297.4	14794.2	8340.9
4.8	13752	10074.9	14779	8338.8
5	13529.3	9889.3	16233.1	9159.8
5.2	13346.6	9726.2	16012	9034.5
5.4	13220.3	9600.8	15666.6	8840.5
5.6	13158.5	9518.5	15620	8816.2
5.8	13150.4	9473.5	15510	8755.8
6	13160.4	9442.4	15341.9	8662.9
6.2	13184.9	9424.2	15191	8579.6
6.4	13225.1	9417.6	15063.4	8509.5
6.6	13308.7	9438.8	14983.6	8466.1
6.8	13427.9	9475.9	14863.6	8399
7	13585.4	9531.3	14695.4	8304
7.2	13781.2	9607.6	14550.7	8222
7.4	14011.1	9702.8	14421.4	8148.7
7.6	14273.9	9817.4	14278.5	8067.6
7.8	14366.9	9805.9	14140.1	7988.8
8	14209.6	9760	14152.9	7995.7
8.2	13330.1	9489.6	13867.2	7831.9

Table 6.2.1-3
BLOWDOWN MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 4 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
8.4	12315.4	9048.1	13714	7745
8.6	12049.6	8903.2	13593.2	767.9
8.8	12126.7	8916.3	13393.2	7563.2
9	12199.3	8910.2	13214.6	7461.6
9.2	12233.3	8881.5	13040	7362.2
9.4	12300.9	8878	12859.4	7259.4
9.6	12345.9	8850.3	12683	7158.9
9.8	12329.1	8780.7	12507.8	7058.9
10	12294.9	8706.9	12346.2	6966.7
10.2	12241.2	8622.6	12180.3	6871.9
10.4	12106.4	8486.2	12023.6	6782.3
10.6	11880.8	8299.4	11889.1	6705.4
10.8	11639.6	8114.8	11751.9	6626.6
11	11401.5	7938.7	11618.6	6550.1
11.2	11136.8	7750.9	11502.3	6483.3
11.4	10873	7573.8	11387.2	6417.1
11.6	10658.5	7435.8	11265.8	6347.1
11.8	10464.6	7310.7	11148.7	6279.9
12	10253.1	7173.2	11045.3	6220.4
12.2	10053.5	7046.7	10932.5	6155.4
12.4	9874.6	6933.3	10822.3	6092

Table 6.2.1-3
BLOWDOWN MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 5 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
12.6	9684	6810.4	10722.9	6034.7
12.8	9497	6692.8	10620.3	5975.5
13	9327.7	6588.4	10516.9	5915.7
13.2	9155.8	6481.1	10421.9	5860.9
13.4	8982.2	6373.5	10327	5806.2
13.6	8816.8	6273.3	10232.5	5751.7
13.8	8667.6	6184	10135.5	5695.9
14	8521.4	6095.2	10044.1	5643.5
14.2	8380.1	6008.7	9948.1	5588.7
14.4	8235.7	5918.9	9843.2	5529.1
14.6	8079.9	5821.4	9723.7	5461.5
14.8	7911.6	5716.4	9606.7	5395.9
15	7740.3	5607.4	9486.9	5329.1
15.2	7579.2	5499.2	9377.5	5268.3
15.4	7443.9	5401.2	9287.3	5212.2
15.6	7332.6	5314	9213.9	5148
15.8	7236.3	5235.9	9200.4	5101.4
16	7144.9	5164.1	9194.4	5045.7
16.2	7050.4	5095.2	9244.6	5014
16.4	6949.9	5027.8	9282.9	4975.4
16.6	5842.1	4961.6	9338.5	4951

Table 6.2.1-3
BLOWDOWN MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 6 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
16.8	6726.7	4896.6	9380	4927.9
17	6606.7	4834.3	9356.4	4881.3
17.2	6482.6	4774.4	9325.8	4838.8
17.4	6348.9	4712.8	9175.3	4738.7
17.6	6221.9	4660.8	9193.7	4727.4
17.8	6099.1	4614.2	8877.6	4553.3
18	5980.7	4572.5	9020.6	4611.7
18.2	5877	4540.1	8517.1	4348
18.4	5822.8	4540.2	8488	4322
18.6	5813.9	4618.1	8238.7	4212.5
18.8	5683	4712.2	8215.9	4180.8
19	5352.2	4749.9	7873.7	3994.1
19.2	4939.2	4736.5	7742	3867.1
19.4	4391.5	4569.4	7364.4	3630.9
19.6	3892	4369.1	6225.8	2998.5
19.8	3429.4	4076.3	11041	5196
20	3038.1	3722.2	8589.4	4118
20.2	2816.7	3476.3	4022.2	1929.3
20.4	2563.1	3175.2	8252.9	3570.9
20.6	2276.1	2831	7793.4	3369.1
20.8	2088.3	2606.4	5198.2	2256.7

Table 6.2.1-3
BLOWDOWN MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 7 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
21	1952.9	2443	3636.9	1579
21.2	1811.9	2270.2	2806.1	1170.7
21.4	1662	2086.1	4420.9	1666.6
21.6	1514.6	1904.6	6026.8	2204.2
21.8	1384.8	1744.6	5350.7	1932.3
22	1268.2	1600	4511.2	1612.8
22.2	1154.5	1458.5	4119.9	1451.8
22.4	1057.5	1337.9	3840.2	1323.5
22.6	952.7	1207.1	3486.8	1171.6
22.8	857.2	1087.3	3061.1	1001.4
23	778.6	988.6	2674.1	851.1
23.2	713.1	906	2300.7	712.5
23.4	667.6	848.8	1921.6	580
23.6	625.8	796.2	1549.8	457.1
23.8	576.7	734	1149.5	332.6
24	525.7	669.4	723.3	206.4
24.2	469.4	598.1	317.3	89.9
24.4	410.9	523.8	26.5	7.5
24.6	351.3	448.1	0	0
24.8	296.6	378.5	0	0
25	240.1	306.7	180.4	51.5

Table 6.2.1-3
BLOWDOWN MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 8 of 8)

	Break Path No. 1[(a)]		Break Path No. 2[(b)]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
25.2	182.9	233.8	110.3	31.4
25.4	120.5	154.3	74.7	21.2
25.6	70	89.8	53.5	15.2
25.8	17.6	22.7	0	0
26	0	0	0	0

a) M&E exiting from the steam generator side of the break.

b) M&E exiting from the broken loop reactor coolant pump side of the break.

Table 6.2.1-3A
REFLOOD MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 1 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
26	0	0	0	0
26.5	0	0	0	0
26.7	0	0	0	0
26.8	0	0	0	0
26.9	0	0	0	0
27	0	0	0	0
27	12.7	14.9	0	0
27.1	66.4	78.3	0	0
27.2	34.2	40.4	0	0
27.4	34.2	40.3	0	0
27.5	41.7	49.1	0	0
27.6	49.8	58.7	0	0
27.7	55.8	65.8	0	0
27.8	61.3	72.3	0	0
27.9	66.6	78.5	0	0
28	71.5	84.3	0	0
28.1	76.2	89.9	0	0
28.1	78.5	92.6	0	0
28.2	80.7	95.2	0	0
28.3	85.1	100.3	0	0
28.4	89.2	105.2	0	0

Table 6.2.1-3A
REFLOOD MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 2 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
28.5	93.3	110	0	0
28.6	97.2	114.6	0	0
28.7	100.9	119	0	0
28.8	104.6	123.4	0	0
28.9	108.2	127.6	0	0
29	111.6	131.7	0	0
29.1	115	135.7	0	0
30.1	145	171.1	0	0
31.1	170.2	200.9	0	0
32.1	584.1	693.5	5264.2	729.4
33.1	610.1	724.9	5441.5	790
34.1	602.5	715.9	5381.4	784.2
35.1	593.6	705.2	5308.1	776
35.9	586.1	696.2	5246.3	768.8
36.1	584.3	694	5230.6	767
37.1	575	682.8	5152.4	757.7
38.1	565.9	671.9	5074.9	748.5
39.1	557	661.3	4998.9	739.4
40.1	548.4	651	4924.9	730.5
40.6	544.3	646	4888.6	726.1
41.1	540.2	641.1	4852.9	721.8

Table 6.2.1-3A
REFLOOD MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 3 of 8)

	Break Path No. 1[(a)]		Break Path No. 2[(b)]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
42.1	532.2	631.6	4783	713.4
43.1	524.5	622.4	4715.3	705.2
44.1	517.1	613.5	4649.6	697.2
45.1	415.3	491.9	3693	589.7
46.1	409.7	485.2	3641.6	583.6
46.2	392	464.2	3399.8	571.9
47.1	561.4	666.5	368	286
48.1	556.4	660.6	376.7	283.2
49.1	538.3	638.9	358	272.9
50.1	520.6	617.7	350.6	262.9
51.1	504.6	598.5	343.9	253.9
51.9	492.3	583.8	338.7	247
52.1	489.3	580.2	337.5	245.4
53.1	474.6	562.6	331.4	237.2
54.1	460.5	545.9	325.6	229.5
55.1	447.1	529.8	320	222.1
56.1	434.2	514.4	314.7	215.1
57.1	421.8	499.6	309.7	208.4
58.1	409.9	485.4	304.8	202.1
59.1	398.5	471.9	300.2	196
60.1	387.6	458.9	295.8	190.2

Table 6.2.1-3A
REFLOOD MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 4 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
61.1	377.1	446.4	291.6	184.7
62.1	367.1	434.4	287.6	179.5
63.1	357.4	422.9	283.8	174.4
64.1	348.2	412	280.1	169.7
65.1	339.4	401.4	276.6	165.1
66.1	330.9	391.4	273.3	160.8
66.5	327.6	387.5	272	159.1
67.1	322.8	381.7	270.1	156.7
68.1	315.1	372.5	267.1	152.8
69.1	307.6	363.7	264.2	149.1
70.1	300.6	355.3	261.5	145.5
71.1	293.8	347.3	258.9	142.2
72.1	287.3	339.6	256.4	139
73.1	281.2	332.3	254.1	136
74.1	275.3	325.3	251.8	133.1
75.1	269.7	318.7	249.7	130.4
76.1	264.3	312.3	247.7	127.8
77.1	259.3	306.3	245.8	125.4
78.1	254.4	300.6	244	123.1
79.1	249.8	295.1	242.3	120.9
80.1	245.5	289.9	240.7	118.8

Table 6.2.1-3A
REFLOOD MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 5 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
81.1	241.3	285	239.1	116.9
82.1	237.4	280.4	237.7	115
83.1	233.6	275.9	236.3	113.3
84.1	230.1	271.7	235	111.7
85.1	226.8	267.8	233.8	110.1
86.1	223.6	264	232.7	108.7
86.8	221.5	261.5	231.9	107.7
87.1	220.6	260.5	231.6	107.3
89.1	215.1	254	229.6	104.8
91.1	210.2	248.2	227.9	102.6
93.1	205.9	243.1	226.4	100.6
95.1	202.1	238.6	225	98.9
97.1	198.8	234.7	223.8	97.4
99.1	195.9	231.3	222.8	96.1
101.1	193.4	228.3	221.9	95
103.1	191.1	225.6	221.2	94
105.1	189.2	223.4	220.5	93.2
107.1	187.6	221.4	219.9	92.5
109.1	186.2	219.8	219.4	91.8
111.1	185	218.4	219	91.3
112	184.6	217.9	218.8	91.1

Table 6.2.1-3A
REFLOOD MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 6 of 8)

	Break Path No. 1[(a)]		Break Path No. 2[(b)]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
113.1	184.1	217.3	218.7	90.9
115.1	183.3	216.3	218.4	90.5
117.1	182.6	215.6	218.1	90.2
119.1	182.1	215	217.9	90
121.1	181.8	214.5	217.8	89.8
123.1	181.5	214.2	217.7	89.6
125.1	181.3	214	217.6	89.5
127.1	181.2	213.9	217.5	89.5
129.1	181.2	213.9	217.5	89.4
131.1	181.2	213.9	217.5	89.4
133.1	181.3	214	217.5	89.4
135.1	181.5	214.2	217.5	89.5
137.1	181.7	214.4	217.6	89.5
139.1	181.9	214.7	217.6	89.6
139.8	182	214.8	217.7	89.6
141.1	182.2	215	217.7	89.7
143.1	182.5	215.4	217.8	89.8
145.1	182.8	215.8	217.9	89.9
147.1	183.2	216.2	218	90
149.1	183.5	216.6	218.1	90.1
151.1	183.9	217	218.2	90.2

Table 6.2.1-3A
REFLOOD MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 7 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
153.1	184.2	217.5	218.3	90.4
155.1	184.6	217.9	218.4	90.5
157.1	185	218.4	218.5	90.6
159.1	185.4	218.8	218.6	90.8
161.1	185.8	219.3	218.7	90.9
163.1	186.2	219.8	218.8	91
165.1	186.6	220.2	218.9	91.2
167.1	187	220.7	219	91.3
168.8	187.4	221.1	219.1	91.5
169.1	187.4	221.2	219.1	91.5
171.1	187.8	221.7	219.2	91.6
173.1	188.3	222.2	219.4	91.8
175.1	188.7	222.7	219.5	91.9
177.1	189.1	223.2	219.6	92.1
179.1	189.5	223.7	219.7	92.2
181.1	189.9	224.2	219.8	92.4
183.1	190.4	224.7	220	92.5
185.1	190.8	225.2	220.1	92.7
187.1	191.2	225.7	220.2	92.9
189.1	191.7	226.2	220.3	93
191.1	192.1	226.8	220.5	93.2

Table 6.2.1-3A
REFLOOD MASS AND ENERGY RELEASE RATES
FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION
(Sheet 8 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
193.1	192.5	227.3	220.6	93.3
195.1	193	227.8	220.7	93.5
197.1	193.4	228.3	220.9	93.7
198.9	193.8	228.8	221	93.8

a) M&E exiting from the steam generator side of the break.

b) M&E exiting from the broken loop reactor coolant pump side of the break.

TABLE 6.2.1-3B
PRINCIPAL PARAMETERS DURING REFLOOD FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION)
(Sheet 1 of 2)

	Flooding						Total	Injection Accumulator	Spill	
Time (s)	Temp (°F)	Rate (in/s)	Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction		(lbm/s)		Enthalpy
26	185.1	0	0	0	0	0.25	0	0	0	0
26.7	182.9	21.236	0	0.53	1.65	0	8224.8	8224.8	0	89.82
27	181.2	25.322	0	1.02	1.59	0	8147.6	8147.6	0	89.82
28.1	180.1	2.789	0.303	1.5	4.87	0.342	7843.5	7843.5	0	89.82
29	180	2.696	0.419	1.62	7.67	0.365	7655.5	7655.5	0	89.82
32.2	180.1	5.516	0.635	2.01	16.11	0.633	6929.4	6389.6	0	89.68
34.1	180	5.11	0.69	2.29	16.12	0.629	6580.5	6044.4	0	89.67
35.9	180.2	4.836	0.713	2.51	16.12	0.627	6355.7	5815.5	0	89.67
40.6	181.5	4.409	0.736	3	16.12	0.619	5871.1	5320.3	0	89.65
46.2	183.9	3.454	0.743	3.5	16.12	0.548	4127.7	3545.7	0	89.56
47.1	184.3	4.415	0.746	3.58	15.83	0.632	546.3	0	0	88
51.9	187.6	3.876	0.747	4	14.25	0.626	561.2	0	0	88
59.1	194.1	3.204	0.746	4.54	12.57	0.615	580.4	0	0	88
66.5	201.8	2.706	0.743	5	11.48	0.601	592.8	0	0	88
76.1	212.2	2.268	0.74	5.51	10.75	0.581	602.3	0	0	88
86.8	222.6	1.973	0.738	6	10.5	0.562	607.8	0	0	88
99.1	232.3	1.796	0.737	6.51	10.63	0.546	610.7	0	0	88
112	240.7	1.713	0.74	7	11.01	0.538	611.9	0	0	88
127.1	249.1	1.679	0.744	7.55	11.58	0.536	612.3	0	0	88

TABLE 6.2.1-3B
PRINCIPAL PARAMETERS DURING REFLOOD FOR THE DESIGN BASIS ACCIDENT - DEPSG
(MINIMUM SAFETY INJECTION)
(Sheet 2 of 2)

	Flooding						Total	Injection Accumulator	Spill	
Time (s)	Temp (°F)	Rate (in/s)	Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction		(lbm/s)		Enthalpy
139.1	255	1.675	0.748	7.98	12.06	0.537	612.3	0	0	88
139.8	255.3	1.675	0.748	8	12.09	0.537	612.3	0	0	88
155.1	261.9	1.679	0.754	8.53	12.72	0.539	612.1	0	0	88
658.8	267	1.685	0.759	9	13.27	0.541	611.8	0	0	88
185.1	272.4	1.693	0.765	9.55	13.91	0.544	611.5	0	0	88
198.9	276.4	1.701	0.77	10	14.45	0.547	611.3	0	0	88

TABLE 6.2.1-4

POST-REFLOOD MASS AND ENERGY RELEASE RATES FOR THE DESIGN BASIS ACCIDENT - DEPSG (MINIMUM SAFETY INJECTION)

(Sheet 1 of 3)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
199	261.6	326.7	359.1	140.4
204	260.2	324.9	360.5	140.5
209	259.9	324.6	360.8	140.4
214	259.6	324.3	361.1	140.3
219	259.3	323.9	361.4	140.1
224	259	323.5	361.7	140
229	258.6	323	362.1	139.9
234	258.2	322.5	362.5	139.8
239	257.8	321.9	363	139.7
244	257.3	321.3	363.4	139.6
249	256.7	320.7	364	139.6
254	257.2	321.3	363.5	139.2
259	256.6	320.5	364.1	139.2
264	255.9	319.7	364.8	139.1
269	255.2	318.8	365.5	139.1
274	255.5	319.1	365.2	138.8
279	254.7	318.1	366	138.8
284	253.8	317	366.9	138.9
289	253.9	317.1	366.8	138.6
294	253.9	317.1	366.8	138.4
299	252.8	315.8	367.9	138.5
304	252.7	315.6	368	138.3
309	252.4	315.3	368.3	138.2
314	252.1	314.8	368.6	138
319	251.6	314.3	369.1	137.9
324	251.1	313.6	369.6	137.9

TABLE 6.2.1-4

POST-REFLOOD MASS AND ENERGY RELEASE RATES FOR THE DESIGN BASIS ACCIDENT - DEPSG (MINIMUM SAFETY INJECTION)

(Sheet 2 of 3)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
329	250.4	312.8	370.3	137.8
334	249.7	311.8	371.1	137.8
339	249.6	311.8	371.1	137.6
344	249.5	311.6	371.3	137.4
349	248.3	310.1	372.4	137.5
354	248.6	310.5	372.1	137.2
359	247.9	309.6	372.8	137.2
364	246.9	308.4	373.8	137.2
369	246.6	307.9	374.1	137.1
374	246.7	308.1	374	136.8
379	245.7	306.8	375	136.9
384	245.1	306.1	375.6	136.8
389	244.7	305.7	376	136.7
394	244.6	305.4	376.2	136.5
399	243.7	304.4	377	136.5
384	245.1	306.1	375.6	136.8
389	244.7	305.7	376	136.7
394	244.6	305.4	376.2	136.5
404	243.6	304.2	377.1	136.3
409	243.1	303.6	377.6	136.2
414	242.5	302.9	378.2	136.2
419	241.9	302.1	378.8	136.1
424	241.5	301.7	379.2	136
429	241.2	301.3	379.5	135.9
434	240.7	300.6	380	135.8
439	240.2	300	380.5	135.7

TABLE 6.2.1-4

POST-REFLOOD MASS AND ENERGY RELEASE RATES FOR THE DESIGN BASIS ACCIDENT - DEPSG (MINIMUM SAFETY INJECTION) (Sheet 3 of 3)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
444	239.5	299.1	381.2	135.7
449	95.4	119.2	525.3	174
586.7	95.4	119.2	525.3	174
586.8	99.6	123.5	521.1	173
589	99.5	123.4	521.2	172.9
1159	86.6	107.2	534.1	166.2
1159.8	86.6	107.2	385.4	191.7
1499.8	81.1	100.4	390.9	186.1
1500	81.1	100.3	390.9	187.4
1726.8	81.1	100.3	390.9	187.4
1726.9	77.7	89.4	394.3	93.5
2000	74.5	85.8	397.5	94
2000.1	74.5	85.8	397.5	97.3
2500	71.4	82.2	400.6	97.9
2500.1	71.4	82.2	400.6	95.5
3000	68.3	78.6	403.7	96.1
3000.1	68.3	78.6	403.7	93.7
3500	65.1	74.9	406.9	94.3
3500.1	65.1	74.9	406.9	93.4
3600	64.5	74.2	407.5	93.5

a) M&E exiting from the steam generator side of the break.

b) M&E exiting from the broken loop reactor coolant pump side of the break.

TABLE 6.2.1-4A

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TABLE 6.2.1-4B
THIS TABLE HAS BEEN DELETED

TABLE 6.2.1-5
CONTAINMENT INITIAL CONDITIONS

Reactor Coolant System (100.6 percent ESDR)	3634
Average coolant temperature, F[(a)]	595.1
Mass of reactor coolant, lbm	572.12×10^3
Energy of reactor coolant, Btu	340.8×10^6
Containment	
Pressure, psig	-0.5 to 1.5
Inside temperature, F	120
Component cooling water temperature, F	105 (LOCA only)
Service water temperature, F	102 (LOCA only)
Refueling water temperature, F	120
Accumulators	
Total Volume, ft^3	3392.4
Cover gas pressure, psia	728
Temperature, F	120

a) RCS Coolant temperatures include uncertainty of +5.9 °F.

TABLE 6.2.1-6

STRUCTURAL HEAT SINKS
(Sheet 1 of 2)

No.	Description	Material	Area (ft^2)	Thickness (inches)	Initial Temp (°F)
1	Containment dome hemisphere	Paint on steel	28,628	0.006996	120
		Steel		0.500400	
		Linear air gap		0.124800	
		Concrete		29.499600	
		Paint on concrete		0.027996	
2	Misc. steel (filters, coils, hangers)	Paint on steel	23,819	0.007	120
		Stee		0.263	
3	.Misc. steel (piping, shielding, beams)	Paint on steel	4,586	0.006996	120
		Steel		0.160980	
4	Slabs and walls, 2-sided	Paint on concrete	172,676	0.027996	120
		Concrete		12.000000	
5	Ventilation ducts	Paint on steel	40,257	0.006996	120
		Steel		0.060000	
6	Misc. steel (platforms, ladders, ...)	Paint on steel	6,334	0.006996	120
		Steel		0.049992	
7	Cylindrical section of containment wall	Paint on steel	81,642	0.006996	120
		Steel		0.375600	
		Liner air gap		0.124800	
		Concrete		53.624400	
		Paint on concrete		0.027996	
8	Misc. steel (crane sheel, beams, ...)	Paint on steel	1,866	0.006996	120
		Steel		0.750000	
9	Misc. steel (wheels, girders, ...)	Paint on steel	528	0.006996	120
		Steel		4.002000	

TABLE 6.2.1-6

STRUCTURAL HEAT SINKS
(Sheet 2 of 2)

No.	Description	Material	Area (ft^2)	Thickness (inches)	Initial Temp (°F)
10	Foundation mat	Paint on concrete	11,395	0.027996	120
		Concrete		30.00000	
		Liner air gap		0.124800	
		Steel		0.240000	
		Liner air gap		0.124800	
		Concrete		143.964000	
11	Misc. steel (boxes, pumps, ...)	Paint on steel	23,359	0.006996	120
		Steel		0.150000	
12	Misc. steel (piping, rims, crane, ...)	Paint on steel	21,684	0.006996	120
		Steel		0.279600	
13	Misc. steel (trolley girders, ...)	Paint on steel	1,528	0.006996	120
		Steel		2.000400	
14	Girders	Paint on steel	16,631	0.006996	120
		Steel		2.250000	
15	Trolley girders	Paint on steel	22,987	0.006996	120
		Steel		0.096000	

TABLE 6.2.1-7
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TABLE 6.2.1-8
THERMOPHYSICAL PROPERTIES OF STRUCTURAL HEAT SINK MATERIALS

Material	Thermal Conductivity (Btu/hr-ft-°F)	Volumetric Heat Capacity (Btu/hr-ft^3-°F)	Specific Heat (Btu/lbm-°F)	Density (lbm/ft^3)
1) Steel	26	53.9	0.11	490
2) Concrete	0.8	23.2	0.16	145
3) Paint on steel	0.0875	0.1	0.1	1
4) Paint on concrete	0.07	0.1	0.1	1
5) Liner air gap	0.0161	0.0167	0.20875	0.08

TABLE 6.2.1-9

CHRONOLOGY OF EVENTS FOR LOCA DESIGN BASIS ACCIDENT DOUBLE-ENDED PUMP SUCTION GUILLOTINE, MINIMUM SAFETY INJECTION
(Sheet 1 of 2)

Time (sec)	Event Description
0.0	Break Occurs and Loss of Offsite Power is Assumed
.65	Containment Spray Actuation Pressure Setpoint (19.7 psia; Analysis Value) Reached
2.6	Compensated Pressure Reactor Trip (1,859.7 psia) Reached and Turbine Trip Occurs
4.3	Low Pressurizer Pressure SI Setpoint (1,715 psia) Reached (Safety Injection Begins coincident with Low Pressurizer Pressure SI Setpoint)
11.31	Feedwater Isolation Valves Closed
15.1	Broken Loop Accumulator Begins Injecting Water
15.3	Intact Loop Accumulator Begins Injecting Water
26.0	End of Blowdown Phase
26.0	Accumulator Mass Adjustment for Refill Period
31.30	Pumped Safety Injection Begins (includes 27 Second Diesel Delay)
44.76	Broken Loop Accumulator Water Injection Ends
46.11	Intact Loop Accumulator Water Injection Ends
74.95	Containment Spray Pump (RWST) Begins
198.9	End of Reflood for Minimum Safeguards Case
446.6	Containment Peak Temperature Occurs (266.1°F)
449.0	M&E Release Assumption: Broken Loop Steam Generator (SG) Equilibration When the Secondary Temperature is the Saturation (T_{sat}) At Containment Design Pressure of 64.7 psia
586.8	M&E Release Assumption: Broken Loop SG Equilibration at Containment Pressure of 54.7 psia
1,159.8	Switchover to Cold Leg Recirculation Begins

TABLE 6.2.1-9

CHRONOLOGY OF EVENTS FOR LOCA DESIGN BASIS ACCIDENT DOUBLE-ENDED PUMP SUCTION GUILLOTINE, MINIMUM SAFETY INJECTION
(Sheet 2 of 2)

Time (sec)	Event Description
1,572.4	M&E Release Assumption: Intact Loop SG Equilibration When the Secondary Temperature is the Saturation (T_{sat}) at Containment Design Pressure of 64.7 psia
1,721.7	Containment Spray Terminated
1,726.8	M&E Release Assumption: Intact Loop SG Equilibration at Containment of 44.7 psia
3,407.0	Containment Peak Pressure Occurs (59.15 psia)
10,800.0	Hot Leg Recirculation Switchover
7.8E+6	Transient Modeling Terminated

TABLE 6.2.1-10
CHRONOLOGY OF EVENTS FOR MAIN STEAM LINE BREAK WHICH RESULTS IN THE PEAK PRESSURE 4.7 FT^2 SPLIT RUPTURE AT 30 PERCENT POWER

INITIAL CONTAINMENT PRESSURE = 1.5 psig

Event	Time (sec)
Break occurs	0.0
Feedwater isolation valves close	11.0
Main steam isolation valves close	13.5
Maximum temperature of 311.1°F is reached	50.2
Initiation of containment spray	76.7[(a)]
Auxiliary feedwater is manually isolated	600.0
Peak pressure of 39.0 psig is reached	620.2
Dryout Time	800.0
End of analysis	86400.0

a) See Section 6.2.1.4.8, Item 5.

TABLE 6.2.1-11

DOUBLE-ENDED HOT LEG BREAK SEQUENCE OF EVENTS

Time (sec)	Event Description
0.0	Break Occurs, and Loss-of-Offsite Power are Assumed
2.2	Compensated Pressurizer Pressure for Reactor Trip (1,859.7 psia) Reached and Turbine Trip Occurs
3.9	Low-Pressurizer Pressure SI Setpoint (1,715 psia) Reached - Feedwater Isolation Signal
10.91	Feedwater Isolation Valves Closed
12.4	Broken Loop Accumulator Begins Injecting Water
12.4	Intact Loop Accumulator Begins Injecting Water
21.5	Peak Temperature Occurs (260.5°F)
22.0	Peak Pressure Occurs (55.53 psia)
22.4	End of Blowdown Phase
50.0	Transient Modeling Terminated

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TABLE 6.2.1-12

DOUBLE-ENDED PUMP SUCTION BREAK SEQUENCE OF EVENTS (MAXIMUM SAFEGUARDS)
(Sheet 1 of 2)

Time (sec)	Event Description
0.0	Break Occurs and Loss of Offsite Power is Assumed
.648	Containment Spray Actuation Pressure Setpoint (19.7 psia; Analysis Value) Reached
2.6	Compensated Pressurizer Pressure Reactor Trip (1,859.7 psia) Reached and Turbine Trip Occurs
4.3	Low Pressurizer Pressure SI Setpoint (1,715 psia) Reached (Safety Injection Begins coincident with Low Pressurizer Pressure SI Setpoint)
11.31	Feedwater Isolation Valves Closed
15.1	Broken Loop Accumulator Begins Injecting Water
15.3	Intact Loop Accumulator Begins Injecting Water
24.01	Containment Peak Temperature Occurs (259.1°F)
26.0	End of Blowdown Phase
26.0	Accumulator Mass Adjustment for Refill Period
31.30	Pumped Safety Injection Begins (Includes 27 Second Diesel Delay)
45.04	Broken Loop Accumulator Water Injection Ends
46.44	Intact Loop Accumulator Water Injection Ends
74.56	Containment Peak Pressure Occurs (55.18 psia)
74.95	Containment Spray Pump (RWST) Begins
184.79	End of Reflood for Maximum Safeguards Case
709.8	M&E Release Assumption: Broken Loop Steam Generator (SG) Equilibration When the Secondary Temperature is the Saturation (T_{sat}) At Containment Design Pressure of 64.7 psia
941.55	Switchover to Cold Leg Recirculation Begins
1030.7	M&E Release Assumption: Broken Loop SG Equilibration at Containment Pressure of 44.7 psia

TABLE 6.2.1-12

DOUBLE-ENDED PUMP SUCTION BREAK SEQUENCE OF EVENTS (MAXIMUM SAFEGUARDS) (Sheet 2 of 2)

Time (sec)	Event Description
1397.7	Containment Spray Terminated
1475.4	M&E Release Assumption: Intact Loop SG Equilibration When the Secondary Temperature is the Saturation (T_{sat}) at Containment Design Pressure of 64.7 psia
1721.4	M&E Release Assumption: Intact Loop SG Equilibration at Containment of 34.7 psia
10,800.0	Hot Leg Recirculation Switchover
1.0E+7	Transient Modeling Terminated

TABLE 6.2.1-13
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TABLE 6.2.1-39

DOUBLE ENDED HOT LEG GUILLOTINE (DEHLG) BLOWDOWN MASS AND ENERGY RELEASE RATE

(Sheet 1 of 7)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
0	0	0	0	0
0.00111	47522.2	30918.4	47520.6	30916
0.101	43784.1	28636.4	28426	30916
0.201	37592	24563	24848.3	16031.3
0.301	35969.4	23481	22643.4	14443.3
0.402	34793.6	22716.4	21467.4	13511.1
0.502	34288.1	22390.3	20691.9	12855.9
0.601	34235.6	22366.4	20164.8	12383
0.701	33884.2	22180.3	19764.7	12014.1
0.802	33182.6	21793.3	19424.4	11702.7
0.902	32491.7	21428.8	19154.6	11452.2
1	31962.7	21181.1	18938.7	11249.3
1.1	31733.5	21141.7	18721.8	11057.2
1.2	31420.1	21041.9	18587.1	10922.3
1.3	30925	20812.5	18510.2	10828
1.4	30337.4	20510.9	18474.5	10562.9
1.5	29766.7	20205.7	18471.5	10719.9
1.6	29328.2	19980.6	18486.9	10689.7
1.7	28998.2	19824.1	18515.4	10670
1.8	28599.2	19616	18549.9	10655.7

TABLE 6.2.1-39

DOUBLE ENDED HOT LEG GUILLOTINE (DEHLG) BLOWDOWN MASS AND ENERGY RELEASE RATE

(Sheet 2 of 7)

	Break Path No. 1[(a)]		Break Path No. 2[(b)]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
1.9	28067.5	19305.1	18580.2	10642.2
2	27480.3	18946.1	18605.8	10628.4
2.1	26974.9	18639.4	18627.5	10615
2.2	26586.2	18413.6	18642.7	10600.8
2.3	26199.5	18185.9	18647.8	10583.6
2.4	25765.5	17908.8	18637.8	10560.6
2.5	25310.7	17622.2	18615.3	10533
2.6	24896.4	17352.7	18582.8	10502.3
2.7	24517	17104.3	18540.6	10468.3
2.8	24168.3	16874.1	18487.7	10430.6
2.9	23854.9	16666.1	18424.8	10389.1
3	23543.5	16453.5	18352.3	10344.1
3.1	23227.7	16230.9	18267.3	10293.7
3.2	22952.1	16033.4	18172.3	10239.1
3.3	22706.5	15854.9	18069.2	10181.3
3.4	22467.1	15676.2	17957.8	10120.1
3.5	22244.9	15506	17836.2	10054
3.6	22055.5	15357.3	17704.6	9983.2
3.7	21876.2	15212.8	17561.9	9907
3.8	21702.3	15068.8	17403.1	9822.3

TABLE 6.2.1-39

DOUBLE ENDED HOT LEG GUILLOTINE (DEHLG) BLOWDOWN MASS AND ENERGY RELEASE RATE

(Sheet 3 of 7)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
3.9	21554	14941.7	17235	9732.9
4	21422.1	14825.3	17061.5	9641
4.2	21182.7	14607.4	16706.6	9453.7
4.4	20994	14424.1	16341.1	9261.2
4.6	20867.1	14284.2	15973.5	9067.6
4.8	20811.4	14203.4	15611.4	8876.9
5	20795.5	14142.7	15318.8	8725.5
5.2	20833.4	14094.1	14988.5	8550.7
5.4	20910.3	14070	14649.6	8369.9
5.6	20994	14049.1	14340.2	8205.4
5.8	21092.9	14034.3	14026.7	8038.1
6	21215.7	14032.8	13752.5	7892.9
6.2	21374.7	14051.9	13465.7	7739.2
6.4	21567.9	14087.6	13171.9	7580.7
6.6	21806	14143.9	12898.6	7433.9
6.8	22127.1	14248	12638.3	7294.1
7	13407.1	9629	12370.7	7149.7
7.2	16873.5	11756.9	12129.6	7019.8
7.4	17037.3	11815	11889.6	6890.4
7.6	17129.3	11788.8	11670.3	6772.5

TABLE 6.2.1-39

DOUBLE ENDED HOT LEG GUILLOTINE (DEHLG) BLOWDOWN MASS AND ENERGY RELEASE RATE

(Sheet 4 of 7)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
7.8	17233.5	11761.2	11451.8	6654.1
8	17361.7	11772.3	11230	6533.2
8.2	17525.8	11811.4	11020.8	6419.4
8.4	17587.8	11779.7	10809.2	6303.9
8.6	17721.7	11800.1	10602.6	6191.3
8.8	17822.8	11813.6	10396.3	6078.9
9	17982	11862	10191.8	5967.6
9.2	17752.3	11662.9	9988.3	5857.3
9.4	17948.8	11709.8	9785.1	5747.3
9.6	18179.5	11779.3	9587	5640.5
9.8	18400.3	11844.1	9391.3	5535.5
10	18691	11951.1	9195.2	5430.3
10.2	19390.8	12290.3	8999.2	5325.5
10.2	19403.6	12297.4	8987.6	5324.7
10.4	19880.1	12565.5	8803.3	5221.1
10.6	20199.5	12732	8608.3	5117.5
10.8	22132.1	13914.2	8409.5	5012.2
11	24690.6	15492.1	8204.7	4904.2
11.2	23622.2	14746.6	8004	4799.4
11.4	23074.7	14339.3	7781.8	4682.6

TABLE 6.2.1-39

DOUBLE ENDED HOT LEG GUILLOTINE (DEHLG) BLOWDOWN MASS AND ENERGY RELEASE RATE

(Sheet 5 of 7)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
11.6	22719.2	14067.5	7549.1	4562
11.8	22489.5	13905	7311.6	4440.8
12	22455.7	13874.7	7075.4	4323
12.2	22231	13741.9	6839.4	4206.8
12.4	21959.5	13550.9	6611.2	4096.4
12.6	21720.1	13384	6385.8	3988.4
12.8	21471.3	13215.5	6168.4	3885.1
13	21472.2	13019.5	5956.7	3784.2
13.2	20696	12761.4	5738.4	3679.6
13.4	20152.1	12460.7	5511.8	3570.8
13.6	9564.1	6669.8	5280.5	3462.5
13.8	9793.6	6714.7	5020	3341.7
14	9955.2	6759.2	4773.3	3235
14.2	10025.9	6786.4	4544.9	3138.9
14.4	9991.4	6777.2	4330.7	3041.4
14.6	9914.9	6770.4	4151.6	2949.8
14.8	9735.8	6713.4	4028.4	2869.6
15	9569.4	6688.1	3960.7	2799.7
15.2	9303.2	6605.1	3942.2	2742.7
15.4	9043.5	6530.1	3962.9	2704.2

TABLE 6.2.1-39

DOUBLE ENDED HOT LEG GUILLOTINE (DEHLG) BLOWDOWN MASS AND ENERGY RELEASE RATE

(Sheet 6 of 7)

Time (sec)	Break Path No. 1[a]		Break Path No. 2[b]	
	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
15.6	8265.4	6433.6	4005	2679.9
15.8	7326	6307.3	4048.2	2661.3
16	6664.6	6155.3	4085.6	2646.3
16.2	6018.3	5891.4	4106.3	2629.8
16.4	5353.4	5504.5	4111.1	2612.3
16.6	4709.2	4954.2	4092.5	2589.5
16.8	4403.8	2626.2	4045.9	2558.7
17	4205.9	4388.8	3971.4	2521.3
17.2	4034.7	4187.8	3873.6	2480.8
17.4	3873.2	4018.1	3754.9	2437.9
17.6	3749.8	3861.9	3618.5	2393.1
17.8	3622.8	3711.9	3464.6	2344.8
18	3467.9	3549.4	3300.8	2295.5
18.2	3287.3	3367.4	3130.6	2244.4
18.4	3136.8	3200.7	2957.4	2189.5
18.6	2978.2	3045.9	2779.5	2129.1
18.8	2758.9	2876.3	2602.1	2070.7
19	2573.9	2728.5	2426.3	2018.6
19.2	2411	2604.5	2229.1	1959.9
19.4	2262	2482.6	2022.8	1914.4

TABLE 6.2.1-39

DOUBLE ENDED HOT LEG GUILLOTINE (DEHLG) BLOWDOWN MASS AND ENERGY RELEASE RATE

(Sheet 7 of 7)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
19.6	2126.9	2372.9	1784.6	1857.1
19.8	2000.9	2262.5	1537.5	1776.1
20	1889.4	2153.9	1321.2	1611.2
20.2	1801.9	2053.4	1142.3	1408.1
20.4	1741.8	1961.2	1020.6	1263.8
20.6	1338.8	1609.3	952.6	1183
20.8	1062.5	1306.2	836.5	1039.5
21	914.5	1136.4	662.4	824.8
21.2	763.8	953	478.9	598
21.4	636.3	795.3	402.8	505.6
21.6	459.9	572.3	281	353.7
21.8	341.6	424.1	270.4	341.2
22	215.4	265	212.4	268
22.2	147.6	181.2	177.6	225.6
22.4	0	0	0	0

a) M&E exiting from the reactor vessel side of the break.

b) M&E exiting from the steam generator side of the break.

TABLE 6.2.1-40

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TABLE 6.2.1-41

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - REFLOOD MASS AND ENERGY

(Sheet 1 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
26	0	0	0	0
26.5	0	0	0	0
26.7	0	0	0	0
26.8	0	0	0	0
26.9	0	0	0	0
27	0	0	0	0
27	12.7	14.9	0	0
27.1	66.4	78.3	0	0
27.2	34.2	40.4	0	0
27.4	34.2	40.3	0	0
27.5	41.7	49.1	0	0
27.6	49.8	58.7	0	0
27.7	55.8	65.8	0	0
27.8	61.3	72.3	0	0
27.9	66.6	78.5	0	0
28	71.5	84.3	0	0
28.1	76.2	89.9	0	0
28.1	78.5	92.6	0	0
28.2	80.7	95.2	0	0
28.3	85.1	100.3	0	0

TABLE 6.2.1-41

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - REFLOOD MASS AND ENERGY

(Sheet 2 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
28.4	89.2	105.2	0	0
28.5	93.3	110	0	0
28.6	97.2	114.6	0	0
28.7	100.9	119	0	0
28.8	104.6	123.4	0	0
28.9	108.2	127.6	0	0
29	111.6	131.7	0	0
29.1	115	135.7	0	0
30.1	145	171.1	0	0
31.1	170.2	200.9	0	0
32.1	636.2	756.1	5704.1	794.9
33.1	650.2	773.2	5793.3	828
34.1	642.8	764.2	5734.8	822
35.1	634	753.7	5664.2	814
35.6	629.4	748.2	5627.2	809.7
36.1	624.9	742.7	5589.7	805.2
37.1	615.7	731.7	5514.3	796.2
38.1	606.8	721	5439.7	787.2
39.1	598.1	710.6	5366.4	778.3
40.1	589.7	700.5	5295	769.7

TABLE 6.2.1-41

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - REFLOOD MASS AND ENERGY

(Sheet 3 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
41.1	581.6	690.7	5225.5	761.2
42.1	573.7	681.3	5158	753
43.1	566.2	672.3	5092.6	745
44.1	558.9	663.6	5029.1	737.3
45.1	469.9	557.2	4036.7	668.5
45.2	465.7	552	4118.9	647.9
46.1	453.7	537.7	4076.5	629.1
47.2	379.9	449.6	521.7	192.6
48.2	379.2	448.8	523.8	192.7
49.2	377.8	447.2	527.3	192.9
50.2	376.4	445.5	530.8	193
51.2	375	443.8	534.3	193.1
52.1	373.7	442.3	537.4	193.3
52.2	373.6	442.1	537.8	193.3
53.2	372.1	440.4	541.2	193.4
54.2	370.6	438.6	544.7	193.5
55.2	369.1	436.8	548.2	193.7
56.2	367.6	435	551.7	193.8
57.2	366	433.1	555.2	193.9
58.2	364.4	431.2	558.7	194.1

TABLE 6.2.1-41

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - REFLOOD MASS AND ENERGY

(Sheet 4 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
59.2	362.7	429.2	562.3	194.3
60.2	361.1	427.2	566	194.4
61.2	359.3	425.2	569.7	194.6
62.2	357.5	423.1	573.4	194.8
63.2	355.7	420.9	577.2	195
64.2	353.8	418.6	581.1	195.2
65.2	351.9	416.4	585.1	195.4
66.2	349.9	414	589.1	195.7
67	348.3	412.1	592.4	195.9
67.2	347.9	411.6	593.3	195.9
68.2	345.8	409.1	597.5	196.2
69.2	343.6	406.5	601.8	196.5
70.2	341.4	403.9	606.2	196.8
71.2	339.1	401.1	610.7	197.1
72.2	336.8	398.3	615.3	197.4
73.2	334.3	395.4	620	197.8
74.2	331.8	392.5	624.9	198.2
75.2	329.2	389.4	629.8	198.6
76.2	326.6	386.2	634.9	199
77.2	323.8	382.9	640.1	199.4

TABLE 6.2.1-41

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - REFLOOD MASS AND ENERGY

(Sheet 5 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
78.2	321	379.5	645.4	199.9
79.2	318	376	650.9	200.4
80.2	315	372.4	656.6	201
81.2	311.8	368.7	662.3	201.5
82.2	308.5	364.8	668.3	202.1
83.2	905.1	360.7	674.4	202.8
83.5	304.1	359.5	676.3	203
84.2	301.6	356.6	680.7	203.4
85.2	298	352.2	687.2	204.1
86.2	294.2	347.7	693.8	204.9
87.2	290.2	343.1	700.7	205.7
89.2	281.9	333.2	715	207.4
91.2	272.9	322.5	730.4	209.3
93.2	263.1	310.8	746.9	211.5
95.2	252.3	298	764.7	214
97.2	240.4	284	784	216.8
99.2	227.2	268.3	805.3	220
101.2	212.2	250.5	828.9	223.9
103.2	197.4	233	852.4	227.2
103.3	197.3	233	852.5	227.1

TABLE 6.2.1-41

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - REFLOOD MASS AND ENERGY

(Sheet 6 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
105.2	196.2	231.6	855	226.6
107.2	195.1	230.3	857.6	226.1
109.2	193.9	228.9	860.2	225.6
111.2	192.8	227.5	862.8	225
113.2	191.6	226.2	865.3	224.5
115.2	190.5	224.8	867.9	224
117.2	189.3	223.5	870.4	223.5
119.2	188.2	222.1	872.9	223
121.2	187.1	220.8	875.4	222.5
123.2	185.9	219.5	877.9	222
125.2	184.8	218.1	880.3	221.5
127.2	183.7	216.8	882.8	221
127.5	183.5	216.6	883.1	220.9
129.2	182.6	215.5	885.2	220.5
131.2	181.4	214.1	887.6	220
133.2	180.3	212.8	890.1	219.5
135.2	179.2	211.5	892.5	219
137.2	178.1	210.2	894.9	218.5
139.2	177	208.8	897.3	218.1
141.2	175.8	207.5	899.6	217.6

TABLE 6.2.1-41

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - REFLOOD MASS AND ENERGY

(Sheet 7 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
143.2	174.7	206.2	902	217.1
145.2	173.6	204.9	904.4	216.6
147.2	172.5	203.5	906.7	216.2
149.2	171.3	202.2	909.1	215.7
151.2	170.2	200.9	911.5	215.3
153.2	169.1	199.5	913.8	214.8
154.4	168.4	198.7	915.2	214.5
155.2	167.9	198.2	916.2	214.3
157.2	166.8	196.8	918.5	213.9
159.2	165.6	195.5	920.9	213.4
161.2	164.5	194.1	923.2	213
163.2	163.3	192.7	925.6	212.5
165.2	162.2	191.4	927.9	212.1
167.2	161	190	930.3	211.7
169.2	159.8	188.6	932.6	211.2
171.2	158.7	187.2	935	210.8
173.2	157.5	185.9	937.3	210.4
175.2	156.3	184.5	939.6	209.9
177.2	155.2	183.1	942	209.5
179.2	154	181.7	944.3	209.1

TABLE 6.2.1-41

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - REFLOOD MASS AND ENERGY

(Sheet 8 of 8)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
181.2	152.8	180.3	946.6	208.7
183.2	151.6	178.9	948.9	208.3
184.8	150.7	177.8	950.8	208

a) M&E exiting from the steam generator side of the break.

b) M&E exiting from the broken loop reactor coolant pump side of the break.

TABLE 6.2.1-42
DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - PRINCIPAL PARAMETERS DURING REFLOOD
(Sheet 1 of 2)

	Flooding						Total	Injection Accumulator	Spill	
Time (s)	Temp (°F)	Rate (in/s)	Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction		(lb_m/s)		Enthalpy (Btu/lb_m)
26	185.1	0	0	0	0	0.25	0	0	0	0
26.7	182.9	21.236	0	0.53	1.65	0	8224.8	8224.8	0	89.82
27	181.2	25.322	0	1.02	1.59	0	8147.6	8147.6	0	89.82
28.1	180.1	2.789	0.303	1.5	4.87	0.342	7843.5	7843.5	0	89.82
29	180	2.696	0.419	1.62	7.67	0.365	7655.5	7655.5	0	89.82
32.1	180	5.798	0.636	2.01	16.11	0.643	7359.2	6292.5	0	89.56
33.1	180	5.564	0.673	2.17	16.12	0.639	7132.9	6075.8	0	89.55
35.6	180.1	5.106	0.713	2.51	16.12	0.637	6809.6	5742.5	0	89.53
40.1	181.3	4.679	0.736	3.01	16.12	0.631	6349.8	5263.1	0	89.51
45.2	183.13	3.846	0.745	3.5	16.12	0.583	4963.6	3818	0	89.4
47.2	184.2	3.389	0.743	3.65	16.12	0.557	1168.7	0	0	88
52.1	187.4	3.322	0.746	4	16.12	0.557	1170.2	0	0	88
60.2	195.1	3.207	0.75	4.56	16.12	0.555	1173.8	0	0	88
67	202.9	3.102	0.752	5	16.12	0.552	1177.3	0	0	88
75.2	213.1	2.955	0.754	5.52	16.12	0.545	1182.4	0	0	88
83.5	223.2	2.778	0.756	6	16.12	0.534	1188.8	0	0	88
93.2	233.1	2.514	0.757	6.52	16.12	0.51	1198.6	0	0	88
103.3	241.3	2.133	0.755	7	16.12	0.452	1212.4	0	0	88
115.2	249.1	2.053	0.758	7.5	16.12	0.452	1212.8	0	0	88

TABLE 6.2.1-42
DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - PRINCIPAL PARAMETERS DURING REFLOOD
(Sheet 2 of 2)

	Flooding						Total	Injection Accumulator	Spill	
Time (s)	Temp (°F)	Rate (in/s)	Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction		(lb_m/s)		Enthalpy (Btu/lb_m)
127.5	256	1.973	0.761	8	16.12	0.451	1213.1	0	0	88
141.2	262.5	1.887	0.764	8.52	16.12	0.451	1213.6	0	0	88
154.4	267.8	1.806	0.767	9	16.12	0.449	1214	0	0	88
169.2	272.9	1.716	0.77	9.5	16.12	0.447	1214.5	0	0	88
184.8	277.4	1.622	0.773	10	16.12	0.444	1215	0	0	88

TABLE 6.2.1-43

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - POST REFLOOD MASS AND ENERGY RELEASE RATE

(Sheet 1 of 7)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
184.8	167.2	208.9	1052.6	225.7
189.8	167.6	209.4	1052.3	225.4
194.8	167.9	209.8	1051.9	225
199.8	167.1	208.8	1052.7	225
204.8	167.7	209.6	1052.1	224.6
209.8	167.2	209	1052.6	224.5
214.8	166.7	208.3	1053.1	224.4
219.8	167.3	209.1	1052.5	224
224.8	166.8	208.5	1053	223.9
229.8	166.3	207.8	1053.5	223.8
234.8	166.9	208.6	1052.9	223.4
239.8	166.4	207.9	1053.4	223.3
244.8	167	208.6	1052.8	222.9
249.8	166.4	208	1053.4	222.8
254.8	165.9	207.3	1053.9	222.7
259.8	166.5	208	1053.3	222.3
264.8	165.9	207.3	1053.9	222.2
269.8	166.5	208	1053.3	221.8
274.8	165.9	207.4	1053.9	221.7
279.8	166.5	208	1053.3	221.3

TABLE 6.2.1-43

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - POST REFLOOD MASS AND ENERGY RELEASE RATE

(Sheet 2 of 7)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
284.8	165.9	207.3	1053.9	221.2
289.8	165.4	206.6	1054.4	221.1
294.8	165.9	207.3	1053.9	220.8
299.8	165.3	206.6	1054.5	220.7
304.8	165.8	207.2	1054	220.3
309.8	165.2	206.5	1054.6	220.2
314.8	165.7	207.1	1054.1	219.8
319.8	165.1	206.3	1054.7	219.7
324.8	165.6	206.9	1054.2	219.4
329.8	165	206.2	1054.8	219.3
334.8	165.5	206.7	1054.4	218.9
339.8	164.9	206	1055	218.8
344.8	165.3	206.5	1054.5	218.5
349.8	164.7	205.7	1055.1	218.4
354.8	165.1	206.3	1054.7	218
359.8	164.4	205.5	1055.4	217.9
364.8	164.8	206	1055	217.6
369.8	164.2	205.2	1055.6	217.5
374.8	164.6	205.6	1055.3	217.1
379.8	163.9	204.8	1055.9	217.1

TABLE 6.2.1-43

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - POST REFLOOD MASS AND ENERGY RELEASE RATE

(Sheet 3 of 7)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
384.8	164.2	205.2	1055.6	216.7
389.8	163.6	204.4	1056.2	216.6
394.8	163.9	204.8	1055.9	216.3
399.8	164.2	205.2	1055.6	216
404.8	163.7	204.5	1056.1	215.9
409.8	164.1	205.1	1055.7	215.5
414.8	163.6	204.4	1056.2	215.4
419.8	164	204.9	1055.8	215
424.8	163.4	204.2	1056.4	214.9
429.8	163.8	204.7	1056	214.6
434.8	163.2	203.9	1056.6	214.5
439.8	163.6	204.4	1056.2	214.1
444.8	163	203.7	1056.8	214.1
449.8	163.3	204.1	1056.5	213.7
454.8	163.6	204.5	1056.2	213.4
459.8	163	203.7	1056.8	213.3
464.8	163.3	204	1056.5	213
469.8	163.6	204.4	1056.3	212.6
474.8	162.9	203.5	1056.9	212.6
479.8	163.1	203.8	1056.7	212.2

TABLE 6.2.1-43

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - POST REFLOOD MASS AND ENERGY RELEASE RATE

(Sheet 4 of 7)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
484.8	163.3	204.1	1056.5	211.9
489.8	162.6	203.2	1057.2	211.9
494.8	162.8	203.4	1057	211.6
499.8	163	203.6	1056.8	211.3
504.8	163.1	203.8	1056.7	211
509.8	162.3	202.9	1057.5	210.9
514.8	162.4	203	1057.4	210.6
519.8	162.5	203.1	1057.3	210.4
524.8	162.5	203.1	1057.3	215.7
529.8	162.6	203.1	1057.3	215.4
534.8	162.5	203.1	1057.3	215.2
539.8	162.5	203	1057.3	214.9
544.8	162.4	202.9	1057.4	214.6
549.8	162.3	202.8	1057.5	214.4
554.8	162.2	202.6	1057.6	214.1
559.8	162	202.4	1057.8	213.9
564.8	161.8	202.1	1058	213.7
569.8	162.3	202.8	1057.5	213.2
574.8	162	202.4	1057.8	213
579.8	161.7	202	1058.1	212.8

TABLE 6.2.1-43

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - POST REFLOOD MASS AND ENERGY RELEASE RATE

(Sheet 5 of 7)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
584.8	162	202.4	1057.8	212.5
589.8	161.6	201.9	1058.2	212.3
594.8	161.8	202.2	1058	211.9
599.8	161.3	201.5	1058.6	211.8
604.8	161.4	201.7	1058.4	211.5
609.8	161.5	201.7	1058.4	211.2
614.8	161.4	201.7	1058.4	210.9
619.8	161.3	201.5	1058.5	210.6
624.8	161.1	201.3	1058.7	210.4
629.8	161.4	201.6	1058.4	210
634.8	160.9	201	1058.9	209.9
639.8	160.9	201.1	1058.9	209.6
644.8	160.7	200.8	1059.1	209.3
649.8	161	201.1	1058.9	209
654.8	160.9	201.1	1058.9	208.7
659.8	160.6	200.7	1059.2	208.5
664.8	160.5	200.5	1059.3	208.2
669.8	160.4	200.4	1059.4	207.9
674.8	160.8	200.9	1059	207.5
679.8	160.4	200.4	1059.4	207.3

TABLE 6.2.1-43

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - POST REFLOOD MASS AND ENERGY RELEASE RATE

(Sheet 6 of 7)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
684.8	160.4	200.4	1059.5	207
689.8	160.4	200.5	1059.4	206.7
694.8	160.3	200.3	1059.5	206.5
699.8	160	199.9	1059.8	211.5
704.8	159.8	199.7	1060	211.2
709.8	86.5	108.1	1133.3	230.5
939.8	80.9	101.1	1138.9	224.8
941.5	80.9	101.1	1107.3	307.4
1030.6	80.9	101.1	1107.3	307.4
1030.7	88.4	109.5	1099.8	306
1031.5	88.4	109.5	1099.8	306.7
1499.9	88.4	109.54	1099.8	306.7
1500	81.2	100.6	1107	312.6
1721.4	81.2	100.6	1107	312.6
1721.5	77.5	89.1	1110.7	213.4
2000	74.3	85.5	1113.9	214
2000.1	74.3	85.5	1113.9	211.6
2500	71.2	81.9	1117	212.2
2500.1	71.2	81.9	1117	208.6
3000	68	78.3	1120.2	209.2

TABLE 6.2.1-43

DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MAXIMUM ECCS - POST REFLOOD MASS AND ENERGY RELEASE RATE

(Sheet 7 of 7)

	Break Path No. 1[a]		Break Path No. 2[b]	
Time (sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)	Flow (lb_m/sec)	Energy (10^3 Btu/sec)
3000.1	68	78.3	1120.2	206.8
3500	64.9	74.6	1123.3	207.3
3500.1	64.9	74.6	1123.3	203.8
3600	64.3	73.9	1123.9	203.9

a) M&E exiting from the steam generator side of the break.

b) M&E exiting from the broken loop reactor coolant pump side of the break.

TABLE 6.2.1-44

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TABLE 6.2.1-45

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TABLE 6.2.1-46

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TABLE 6.2.1-47

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TABLE 6.2.1-48

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TABLE 6.2.1-49
(Sheet 1 of 2)
LOCA M&E RELEASE ANALYSIS CORE DECAY HEAT FRACTION

Time (sec)	Decay Heat Generation Rate (Btu/Btu)
10	0.053876
15	0.050401
20	0.048018
40	0.042401
60	0.039244
80	0.037065
100	0.035466
150	0.032724
200	0.030936
400	0.027078
600	0.024931
800	0.023389
1,000	0.022156
1,500	0.019921
2,000	0.018315
4,000	0.014781
6,000	0.013040
8,000	0.012000
10,000	0.011262
15,000	0.010097
20,000	0.009350
40,000	0.007778
60,000	0.006958
80,000	0.006424

TABLE 6.2.1-49
(Sheet 2 of 2)
LOCA M&E RELEASE ANALYSIS CORE DECAY HEAT FRACTION

Time (sec)	Decay Heat Generation Rate (Btu/Btu)
100,000	0.006021
150,000	0.005323
200,000	0.004847
400,000	0.003770
600,000	0.003201
800,000	0.002834
1,000,000	0.002580
2,000,000	0.001909
4,000,000	0.001355
6,000,000	0.001091
8,000,000	0.000927
10,000,000	0.000808

TABLE 6.2.1-50
MASS AND ENERGY BALANCE DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) WITH MAXIMUM ECCS
(Sheet 1 of 2)

TIME (SEC)		.00	26.00	26.00+ ε	184.79	1030.67	1721.39	3600
		MASS (10^3 LBM)						
INITIAL	IN RCS AND ACCUMULATOR	781.98	781.98	781.98	781.98	781.98	781.98	781.98
ADDED MASS	PUMPED INJECTION	0	0	0	182.66	1211.64	2032.36	4264.52
	TOTAL ADDED	0	0	0	182.66	1211.64	2030.36	4264.52
***** TOTAL AVAILABLE *****		**781.98**	**781.98**	**781.98**	**964.64**	**1993.62**	**2814.34**	**5046.50**
DISTRIBUTION	REACTOR COOLANT	572.12	58.27	81.71	144.16	144.16	144.16	144.16
	ACCUMULATOR	209.86	145.22	121.79	0	0	0	0
	TOTAL CONTENTS	781.98	203.5	203.5	144.16	144.16	144.16	144.16
EFFLUENT	BREAK FLOW	0	578.47	578.47	808.98	1837.96	2658.65	4890.82
	ECCS SPILL	0	0	0	0	0	0	0
	TOTAL EFFLUENT	0	578.47	578.47	808.98	1837.96	2658.65	4890.82
***** TOTAL ACCOUNTABLE *****		**781.98**	**781.96**	**781.96**	**953.15**	**1982.13**	**2802.82**	**5034.98**

Note: +ε is used to indicate that the column represents the bottom of core recovery conditions which occurs instantaneously after blowdown.

TABLE 6.2.1-50
MASS AND ENERGY BALANCE DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) WITH MAXIMUM ECCS
(Sheet 2 of 2)

TIME (SEC)		.00	26.00	26.00+ ε	184.79	1030.67	1721.39	3600
		MASS (10^3 LBM)						
INITIAL ENERGY	IN RCS, ACCUMULATORS AND STEAM GENERATORS	986.33	986.33	986.33	986.33	986.33	986.33	986.33
ADDED ENERGY	PUMPED INJECTION	0	0	0	16.07	114.25	249.95	630.63
	DECAY HEAT	0	8.64	8.64	28.44	102.81	151.68	261.91
	HEAT FROM SECONDARY	0	5.15	5.15	5.15	5.15	5.15	5.15
	TOTAL ADDED	0	13.79	13.79	49.67	222.21	406.78	897.69
***** TOTAL AVAILABLE *****		**986.33**	**1000.11**	**1000.11**	**1036.00**	**1208.53**	**1393.11**	**1884.02**
DISTRIBUTION	REACTOR COOLANT	340.8	12.87	14.97	38.31	38.31	38.31	38.31
	ACCUMULATOR	18.85	13.04	10.94	0	0	0	0
	CORE STORED	23.94	11.84	11.84	4.91	4.47	4.17	3.33
	PRIMARY METAL	166.19	157.43	157.43	130.13	82.70	64.27	51.19
	SECONDARY METAL	122.15	119.21	119.21	108.79	73.96	53.61	42.62
	STEAM GENERATOR	314.91	324.63	324.63	292.34	190.86	135.89	107.40
	TOTAL CONTENTS	986.33	639.01	639.01	574.48	390.29	296.24	242.85
EFFLUENT	BREAK FLOW	0	360.53	360.53	450.20	806.92	1070.81	1616.50
	ECCS SPILL	0	0	0	0	0	0	0
	TOTAL EFFLUENT	0	360.53	360.53	450.20	806.92	1070.81	1616.50
***** TOTAL ACCOUNTALBE *****		**986.33**	**999.54**	**999.54**	**1024.68**	**1197.22**	**1367.05**	**1859.35**

Note: +ε is used to indicate that the column represents the bottom of core recovery conditions which occurs instantaneously after blowdown.

TABLE 6.2.1-50A

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TABLE 6.2.1-51
MASS AND ENERGY BALANCE DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MINIMUM ECCS
(Sheet 1 of 2)

TIME (SEC)		.00	26.00	26.00+ ε	198.91	586.8	1726.77	3600
		MASS (10^3 LBM)						
INITIAL	IN RCS AND ACCUMULATOR	781.98	781.98	781.98	781.98	781.98	781.98	781.98
ADDED MASS	PUMPED INJECTION	0	0	0	100.57	341.28	964.56	1848.72
	TOTAL ADDED	0	0	0	100.57	341.28	964.56	1848.72
***** TOTAL AVAILABLE *****		**781.98**	**781.98**	**781.98**	**882.55**	**1123.26**	**1746.54**	**2630.7**
DISTRIBUTION	REACTOR COOLANT	572.12	58.27	81.71	140.89	140.89	140.89	140.89
	ACCUMULATOR	209.86	145.22	121.79	0	0	0	0
	TOTAL CONTENTS	781.98	203.5	203.5	140.89	140.89	140.89	140.89
EFFLUENT	BREAK FLOW	0	578.47	578.47	730.16	970.87	1594.09	2478.26
	ECCS SPILL	0	0	0	0	0	0	0
	TOTAL EFFLUENT	0	578.47	578.47	730.16	970.87	1594.09	2478.26
***** TOTAL ACCOUNTABLE *****		**781.98**	**781.96**	**781.96**	**871.05**	**1111.77**	**1734.98**	**2619.15**

Note: +ε is used to indicate that the column represents the bottom of core recovery conditions which occurs instantaneously after blowdown.

TABLE 6.2.1-51
MASS AND ENERGY BALANCE DOUBLE ENDED PUMP SUCTION GUILLOTINE (DEPSG) MINIMUM ECCS
(Sheet 2 of 2)

TIME (SEC)		.00	26.00	26.00+ ε	198.91	586.8	1726.77	3600
		MASS (10^3 LBM)						
INITIAL ENERGY	IN RCS, ACCUMULATORS AND STEAM GENERATORS	986.33	986.33	986.33	986.33	986.33	986.33	986.33
ADDED ENERGY	PUMPED INJECTION	0	0	0	8.85	30.03	107.15	261.29
	DECAY HEAT	0	8.64	8.64	29.96	66.92	152.03	261.97
	HEAT FROM SECONDARY	0	5.15	5.15	5.15	5.15	5.15	5.15
	TOTAL ADDED	0	13.79	13.79	43.97	102.11	264.33	528.41
***** TOTAL AVAILABLE *****		**986.33**	**1000.11**	**1000.11**	**1030.29**	**1088.43**	**1250.65**	**1514.73**
DISTRIBUTION	REACTOR COOLANT	340.8	12.87	14.97	37.35	37.35	37.35	37.35
	ACCUMULATOR	18.85	13.04	10.94	0	0	0	0
	CORE STORED	23.94	11.84	11.84	4.91	4.71	4.19	3.33
	PRIMARY METAL	166.19	157.43	157.43	131.03	96.65	66.5	51.07
	SECONDARY METAL	122.15	119.21	119.21	109.74	89.36	56.18	42.5
	STEAM GENERATOR	314.91	324.63	324.63	295.5	235.9	142.81	107.11
	TOTAL CONTENTS	986.33	639.01	639.01	578.53	463.97	307.02	241.37
EFFLUENT	BREAK FLOW	0	360.53	360.53	440.45	613.16	921.25	1251.86
	ECCS SPILL	0	0	0	0	0	0	0
	TOTAL EFFLUENT	0	360.53	360.53	440.45	613.16	921.25	1251.86
***** TOTAL ACCOUNTALBE *****		**986.33**	**999.54**	**999.54**	**1018.98**	**1077.12**	**1228.27**	**1493.23**

Note: +ε is used to indicate that the column represents the bottom of core recovery conditions which occurs instantaneously after blowdown.

TABLE 6.2.1-52

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TABLE 6.2.1-54
MASS AND ENERGY BALANCE DOUBLE-ENDED HOT LEG GUILLOTINE (DEHLG)

(Sheet 1 of 2)

Time (sec)		.00	22.40	22.40+ ε[(a)]
		Mass (10^3 lb_m)		
Initial Mass	In RCS and ACC	781.98	781.98	781.98
Added Mass	Pumped Injection	0	0	0
	Total Added	0	0	0
***** Total Available *****		781.98	781.98	781.98
Distribution	Reactor Coolant	572.12	80.79	98.33
	Accumulator	209.86	152.71	135.17
	Total Contents	781.98	233.5	233.5
Effluent	Break Flow	0	548.46	548.46
	ECCS Spill	0	0	0
	Total Effluent	0	548.46	548.46
***** Total Accountable *****		781.98	781.96	781.96

(a) + ε is used to indicate that the column represents the bottom of core recovery conditions that occurs instantaneously after blowdown.

TABLE 6.2.1-54
MASS AND ENERGY BALANCE DOUBLE-ENDED HOT LEG GUILLOTINE (DEHLG)

(Sheet 2 of 2)

Time (sec)		.00	22.40	22.40+ ε[(a)]
		Mass (10^3 lb_m)		
Initial Energy	In RCS, ACC, S GEN	986.33	986.33	986.33
Added Energy	Pumped Injection	0	0	0
	Decay Heat	0	8.36	8.36
	Heat from Secondary	0	5.46	5.46
	Total Added	0	13.82	13.82
***** Total Available *****		986.33	1000.15	1000.15
Distribution	Reactor Coolant	340.8	22.61	23.91
	Accumulator	18.85	13.72	12.42
	Core Stored	23.94	9.35	9.35
	Primary Metal	166.19	156.12	156.12
	Secondary Metal	122.15	118.14	118.14
	Steam Generator	314.39	321.17	321.17
	Total Contents	986.33	641.11	641.11
Effluent	Break Flow	0	358.56	358.56
	ECCS Spill	0	0	0
	Total Effluent	0	358.56	358.56
***** Total Accountable *****		986.33	999.67	999.67

(a) + ε is used to indicate that the column represents the bottom of core recovery conditions that occurs instantaneously after blowdown.

TABLE 6.2.1-55

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TABLE 6.2.1-56
LOCA MASS AND ENERGY RELEASES BASES FOR ANALYSIS

Plant model	4 loop, 12-ft core
Core power (license application), MWt	3612
Engineered safeguards design rating, MWt	3628
Nominal inlet temperature, F	558.0
Nominal outlet temperature, F	620.4
Steam pressure, psia	1032
Rod array	17 x 17
Total accumulator mass, lbm (minimum)	202367
Accumulator temperature, F	120
Assumed containment design pressure, psia	64.7
Pumped ECCS Injection (assumed for froth)	
Minimum	See Table 6.2.1-57
Maximum	See Table 6.2.1-57

TABLE 6.2.1-57

LOCA MASS AND ENERGY RELEASES ECCS SAFETY INJECTION FLOW VS. BACK PRESSURE

Pressure (psia)	Minimum Flow Rate (ft^3/sec)	Maximum Flow Rate (ft^3/sec)
14.7	11.8	22.3
34.7	11.1	21.3
54.7	10.4	20.3
74.7	9.7	19.2
94.7	9	18.1
114.7	8.3	16.8

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TABLE 6.2.1-77

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TABLE 6.2.1-78
MAXIMUM PRESSURES - FEEDWATER LINE BREAK AT CONTAINMENT PENETRATION

VOL. NO.	PRESSURE (PSIA)	DIFFERENTIAL PRESSURE (PSI)	TIME (sec)
1	17.409 (19.0842)	2.709 (0.1712)	0.075 (10.0)
2	17.3436 (19.0429)	2.6436 (0.1299)	0.076 (10.0)
3	17.3479 (19.0327)	2.6479 (0.1197)	0.076 (10.0)
4	22.4316 (19.998)	7.7316 (1.085)	0.067 (10.0)
5	18.913	-----	10.0

NOTE:

Values for end of run (t = 10.0 sec) are given in parentheses.

TABLE 6.2.1-79
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TABLE 6.2.1-91

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TABLE 6.2.1-92
MAIN STEAM LINE BREAK AT CONTAINMENT PENETRATION MAXIMUM DIFFERENTIAL PRESSURES

VOLUME NO.	BREAK VOLUME NO.	WALL DIFFERENTIAL PRESSURE (PSI.)	TIME TO REACH PEAK (SECONDS)
1	1	16.32	0.027
2	2	11.72	0.023

TABLE 6.2.1-93

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TABLE 6.2.1-94
PEAK LOADS ON PRIMARY COMPONENTS DUE TO ASYMMETRIC PRESSURIZATION

(Sheet 1 of 2)

COMPONENT	LOAD (Maximum/Minimum)				
Rupture (Cubicle)	F_x	F_y	F_z	M_x	M_z
STEAM GENERATOR					
Main Steam (4)	36.8	22.6	86.9	17107	10746
	-51.4	-126.4	-20.9	-9327	-4889
Main Steam (3)	57.6	0.0	125.9	11774	23749
	-118.6	-172.9	-102.5	-12425	-5042
Feedwater (4)	118.9	79.7	20.0	33812	30728
	-64.5	-2.5	-125.0	-2082	-5478
RHR (4)	34.3	42.7	52.8	9736	10427
	-66.1	-7.0	-37.4	-17217	-21855
Aux. Feed (4)	87.2	15.0	132.6	29217	9953
	-37.4	-11.9	-114.9	-22017	-19243
RC Pump					
Main Steam (4)	5.9	12.7	5.3	642	774
	-5.0	-21.0	-7.6	-984	-823
Main Steam (3)	8.4	12.5	12.2	999	791
	-6.4	-13.8	-11.1	-1144	-894
Feedwater (4)	104.4	5.4	61.5	4113	1436
	-6.1	-7.9	-3.8	-864	-7051

TABLE 6.2.1-94
PEAK LOADS ON PRIMARY COMPONENTS DUE TO ASYMMETRIC PRESSURIZATION

(Sheet 2 of 2)

COMPONENT	LOAD (Maximum/Minimum)				
Rupture (Cubicle)	F_x	F_y	F_z	M_x	M_z
RHR (4)	16.0	10.4	10.1	534	743
	-16.9	-1.2	-9.6	-435	-784
Aux. Feed (4)	3.9	6.1	5.5	495	373
	-3.4	-3.9	-5.9	-432	-339
Pressurizer					
Press. Spray	40.0	1.0	43.2	8107	6287
	-29.5	-91.2	-36.8	-9035	-5508

Notes:

(1) Units are kips and inch-kips

(2) M_y is always zero

(3) Loads due to a RHR Line break are multiplied by 1.0058 for Unit 2

TABLE 6.2.1-95

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TABLE 6.2.1-101

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TABLE 6.2.1-102

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TABLE 6.2.1-103

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TABLE 6.2.1-104

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TABLE 6.2.1-105
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TABLE 6.2.2-1
CONTAINMENT SPRAY SYSTEM COMPONENT DESIGN PARAMETERS

(Sheet 1 of 3)

1. Containment Spray Pump

Quantity	4
Type	Horizontal centrifugal
Design pressure, psig	325
Design temperature, F	300
Design flow rate, gpm	3000
Total design head, ft	585
NPSH required, ft	13

2. Containment Spray Nozzle

Quantity 761/753 Unit 1/Unit 2	
Type	Spraco 1713A
Design flow per nozzle at 40 psi, gpm	15.2 ± 5 percent

3. Refueling Water Storage Tank

Quantity, per unit	1
Usable volume, gal	506,000
Total content, gal	525,000
Boric acid concentration, ppm	2400-2600
Design pressure, ft	50

TABLE 6.2.2-1
CONTAINMENT SPRAY SYSTEM COMPONENT DESIGN PARAMETERS

(Sheet 2 of 3)

Design temperature, F	120
Operating pressure, ft	41 (Hydraulic head)
4. Containment Spray Heat Exchanger	
Quantity	2
Type	Shell and U tube
Overall heat transfer	
(Btu/hr ft^2 F) coefficient	580.0
Flow, gpm	
Shell side	6080
Injection	5800
Recirculation	7200
Inlet Temperature, F	
Shell side, maximum	135
Tube side, maximum	243
Design Pressure, psig	
Shell	165
Tube	325
Design Temperature, F	
Shell	200
Tube	300

TABLE 6.2.2-1
CONTAINMENT SPRAY SYSTEM COMPONENT DESIGN PARAMETERS

(Sheet 3 of 3)

5. Piping and Valves	
Spray Discharge Lines	
Design pressure, psig	325
Design temperature, F	300
Spray Suction Lines	
Design pressure, psig	70
Design temperature, F	300
Chemical Supply Line	
Design pressure, psig	20
Design temperature, F	150
Eductor Piping	
Design pressure, psig	325
Design temperature, F	300
6. Valve Isolation Tank	
Quantity, per unit	2
Type	Vertical
Design pressure, psig	50
Design temperature, F	280

TABLE 6.2.2-2
CONTAINMENT SPRAY SYSTEM DESIGN PARAMETERS

Number of spray trains	2
Flow rate per spray train, gpm (minimum)	
Injection	5800
Recirculation	7200
Number of headers per spray train	7
Spray initiation - time after LOCA (sec.)	Note 1

Note 1:

See Section 6.2.1.4.8, Item 5

TABLE 6.2.2-3
CONTAINMENT DESIGN PARAMETERS

SEE TABLE 6.2.1-1

TABLE 6.2.2-4
CONTAINMENT SPRAY SYSTEM MATERIALS[a]

Component	Quantity	Material
Chemical additive tank	1	SA-240 Type 304
Recirculation sump strainers	2	ASTM 300 Series stainless steel
Spray Pump	4	
Casing		SA-351 CF 8M
Shaft		SA-182 Grade 316L
Impeller		SA-351 CF 8M or CF 3M
Chemical eductor	4	SA-182 Grade F304
Heat exchanger	2	
Tubes		SA-249 Type 304
Shell		SA-516 Grade 70
Valves, 2 1/2 in. or larger	40	SA-351 CF 8
Piping		SA-312 or SA-358
RWST	1	TP 304 or 316
Liner		SA-240 Type 304L
Structural wall		Reinforced concrete
Stop valves, chemical additive tank	4	SA-351 CF 8

a) All pressure boundary materials conform to ASME B&PV Code, Section III, Class 2 or 3.

TABLE 6.2.2-5
SINGLE FAILURE ANALYSIS - CONTAINMENT SPRAY SYSTEM

Component	Malfunction	Comments and Consequences
1. Spray nozzles	Clogged	Large number of nozzles precludes clogging of a significant number.
2. Pumps	Fail to start	Four 50-percent pumps are provided (two on each train). Operation of two on one train is required.
3. Valves		
Automatically operated Containment spray pump isolation valves[(a)]	Fail to open	Two valves are provided. Operation of one is required.
Containment sump recirculation isolation valves (operated from Control Room)	Fail to open	Two lines are in parallel, one to each pair of spray pumps. Operation of one valve in one line is required.
Miniflow recirculation valves	Fail to close	Operator must ensure valve is closed prior to switchover.
4. Heat Exchanger	Clogging of tubes or loss of component cooling water	Two heat exchangers are provided. One must remain operable.
5. Recirculation sump	Clogged	Two sumps are incorporated into system. One must remain unclogged and operable.

a) Open on coincidence of two out of four high-3 containment pressure signals

TABLE 6.2.2-6
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TABLE 6.2.4-1
CONTAINMENT ISOLATION VALVING APPLICATION

(Sheet 1 of 11)

Item	Penetration Number	System	Line or Service	Line Size (Inches)	NRC General Design Criterion or Reg. Guide Met	Isolation Valving Arrangement (Fig. 6.2.4-1)	Fluid Contained	Engineered Safeguard Feature	FSAR Figure Number
1	MI-1	MS	Main Steam From Steam Generator #1	32	57	17	Sat. Steam	No	10.3-1
2	MI-1	MS	MSIV Bypass From Steam Generator #1	4	57	17	Sat. Steam	No	10.3-1
3	MI-1	MS	Drain From Main Steamline #1	2	57	17	Sat. Water	No	10.3-1
4	MI-1	MS	Main Steam to Aux. F.P.T. From Steam Line #1	4	57	17	Sat. Steam	Yes	10.3-1
4a	MI-1	MS	TDAFW Pump Bypass Warm-up Valve	1	57	17	Sat. Steam	No	10.3-1
5	MI-1	MS	Main Steam from Steam Generator #1	8	57	17	Sat. Steam	No	10.3-1
5a	MI-1	MS	N_2 Supply to Steam Generator #1	3/4	57	17	Sat. Water	No	10.3-1
5b	MI-1	MS	Main Steam Safety Valves for Steam Generator #1	6	57	17	Sat. Steam	No	10.3-1
6	MI-2	MS	Main Steam From Steam Generator #2	32	57	17	Sat. Steam	No	10.3-1
7	MI-2	MS	MSIV Bypass From Steam Generator #2	4	57	17	Sat. Steam	No	10.3-1
8	MI-2	MS	Drain From Main Steamline #2	2	57	17	Sat. Water	No	10.3-1
9	MI-2	MS	Main Steam From Steam Generator #2	8	57	17	Sat. Steam	No	10.3-1
9a	MI-2	MS	N_2 Supply to Steam Generator #2	3/4	57	17	Sat. Water	No	10.3-1
9b	MI-2	MS	Main Steam Safety Valves From Steam Generator #2	6	57	17	Sat. Steam	No	10.3.1
10	MI-3	MS	Main Steam From Steam Generator #3	32	57	17	Sat. Steam	No	10.3-1

TABLE 6.2.4-1
CONTAINMENT ISOLATION VALVING APPLICATION

(Sheet 2 of 11)

Item	Penetration Number	System	Line or Service	Line Size (Inches)	NRC General Design Criterion or Reg. Guide Met	Isolation Valving Arrangement (Fig. 6.2.4-1)	Fluid Contained	Engineered Safeguard Feature	FSAR Figure Number
11	MI-3	MS	MSIV Bypass From Steam Generator #3	4	57	17	Sat. Steam	No	10.3-1
12	MI-3	MS	Drain From Main Steamline #3	2	57	17	Sat. Water	No	10.3-1
13	MI-3	MS	Main Steam From Steam Generator #3	8	57	17	Sat. Steam	No	10.3-1
13a	MI-3	MS	N_2 Supply to Steam Generator #3	3/4	57	17	Sat. Water	No	10.3-1
13b	MI-3	MS	Main Steam Safety Valves From Steam Generator #3	6	57	17	Sat. Steam	No	10.3-1
14	MI-4	MS	Main Steam From Steam Generator #4	32	57	17	Sat. Steam	No	10.3-1
15	MI-4	MS	MSIV Bypass From Steam Generator #4	4	57	17	Sat. Steam	No	10.3-1
16	MI-4	MS	Drain From Main Steam Line #4	2	57	17	Sat. Water	No	10.3-1
17	MI-4	MS	Main Steam to Aux. F.P.T. From Steam line #4	4	57	17	Sat. Steam	Yes	10.3-1
17a	MI-4	MS	TDAFW Pump Bypass Warm-up Valve	1	57	17	Sat. Steam	No	10.3-1
18	MI-4	MS	Main Steam From Steam Generator #4	8	57	17	Sat. Steam	No	10.3-1
18a	MI-4	MS	N_2 Supply to Steam Generator #4	3/4	57	17	Sat. Water	No	10.3-1
18b	MI-4	MS	Main Steam Safety Valves From Steam Generator #4	6	57	17	Sat. Steam	No	10.3-1
19	MI-5	FW	Feedwater to Steam Generator #1	18	57	16	Water	No	10.4-9
20	MI-5	FW	Feedwater Sample (FW to Steam Generator #1)	3/4	57	16	Water	No	10.4-9
20a	MV-18	FW	Auxiliary Feedwater to Steam Generator #1	4	57	36	Water	Yes	10.4-11

TABLE 6.2.4-1
CONTAINMENT ISOLATION VALVING APPLICATION

(Sheet 3 of 11)

Item	Penetration Number	System	Line or Service	Line Size (Inches)	NRC General Design Criterion or Reg. Guide Met	Isolation Valving Arrangement (Fig. 6.2.4-1)	Fluid Contained	Engineered Safeguard Feature	FSAR Figure Number
20b	MI-5	FW	N_2 Supply to Steam Generator #1	3/4	57	16	Water	No	10.4-9
20c	MV-18	FW	Feedwater Preheater Bypass Line to S.G. #1	6	57	36	Water	No	10.4-9
20d	MI-5	FW	Feedwater Bypass Line S.G.#1	3	57	16	Water	No	10.4-9
21	MI-6	FW	Feedwater to Steam Generator #2	18	57	16	Water	No	10.4-9
22	MI-6	FW	Feedwater Sample (FW to Steam Generator #2)	3/4	57	16	Water	No	10.4-9
22a	MV-19	FW	Auxiliary Feedwater to Steam Generator #2	4	57	36	Water	Yes	10.4-11
22b	MI-6	FW	N_2 Supply to Steam Generator #2	3/4	57	16	Water	No	10.4-9
22c	MV-19	FW	Feedwater Preheater Bypass Line to S.G. #2	6	57	36	Water	No	10.4-9
22d	MI-6	FW	Feedwater Bypass Line S.G. #2	3	57	16	Water	No	10.4-9
23	MI-7	FW	Feedwater to Steam Generator #3	18	57	16	Water	No	10.4-9
24a	MV-20	FW	Auxiliary Feedwater to Steam Generator #3	4	57	36	Water	Yes	10.4-11
24b	MI-7	FW	N_2 Supply to Steam Generator #3	3/4	57	16	Water	No	10.4-9
24c	MV-20	FW	Feedwater Preheater Bypass Line to S.G. #3	6	57	36	Water	No	10.4-9
24d	MI-7	FW	Feedwater Bypass Line S.G. #3	3	57	16	Water	No	10.4-9
25	MI-8	FW	Feedwater to Steam Generator #4	18	57	16	Water	No	10.4-9
26a	MV-17	FW	Auxiliary Feedwater to Steam Generator #4	4	57	36	Water	Yes	10.4-11
26b	MI-8	FW	N_2 Supply to Steam Generator #4	3/4	57	16	Water	No	10.4-9
26c	MV-17	FW	Feedwater Preheater Bypass Line to S.G. #4	6	57	36	Water	No	10.4-9

TABLE 6.2.4-1
CONTAINMENT ISOLATION VALVING APPLICATION

(Sheet 4 of 11)

Item	Penetration Number	System	Line or Service	Line Size (Inches)	NRC General Design Criterion or Reg. Guide Met	Isolation Valving Arrangement (Fig. 6.2.4-1)	Fluid Contained	Engineered Safeguard Feature	FSAR Figure Number
26d	MI-8	FW	Feedwater Bypass Line S.G.#4	3	57	16	Water	No	10.4-9
27	MI-9	MS	Blowdown From Steam Generator #3	3	57	35	Sat. Water	No	10.3-1
28	MI-10	MS	Blowdown From Steam Generator #2	3	57	35	Sat. Water	No	10.3-1
29	MI-11	MS	Blowdown From Steam Generator #1	3	57	35	Sat. Water	No	10.3-1
30	MI-12	MS	Blowdown From Steam Generator #4	3	57	35	Sat. Water	No	10.3-1
31	MI-13	-	Spare	12	50	-	-	-	-
32	MII-1	CS	Letdown Line to Letdown Heat Exchanger	3	55	37	Water	No	9.3-10
33	MII-2	RH	R.H.R From Hot Leg Loop #4	12	55	11	Water	No	5.4-6
34	MII-3	RH	R.H.R From Hot Leg Loop #1	12	55	11	Water	No	5.4-6
35	MII-4	SI	R.H.R to Cold Leg Loops #1 and #2	10	55	8	Water	Yes	6.3-1
36	MII-5	SI	R.H.R To Cold Leg Loops #3 and #4	10	55	8	Water	Yes	6.3-1
37	MII-6	-	Spare	12	50	-	-	-	-
38	MII-7	-	Spare	24	50	-	-	-	-
39	MII-8	-	Spare	24	50	-	-	-	-
40a	MII-9(A)	-	Maintenance Penetration	2	56	31	Air	No	9.4-6
40b	MII-9(B)	-	Maintenance Penetration	1 1/2	56	31	Air	No	9.4-6
40c	MII-9(C)	-	Maintenance Penetration	2	56	31	Air	No	9.4-6
41	MIII-1	RC	Reactor Make Up Water to Pressurizer Relief Tank & R.C. Pump Stand Pipe	3	56	4	Water	No	5.1-1

TABLE 6.2.4-1
CONTAINMENT ISOLATION VALVING APPLICATION

(Sheet 5 of 11)

Item	Penetration Number	System	Line or Service	Line Size (Inches)	NRC General Design Criterion or Reg. Guide Met	Isolation Valving Arrangement (Fig. 6.2.4-1)	Fluid Contained	Engineered Safeguard Feature	FSAR Figure Number
41a	MIII-1	RC	Penetration Thermal Relief	3/4	56	4	Water	No	5.1-1
42	MIII-2	SI	S.I. To Cold Leg Loops #1, #2, #3, & #4	3	55	9	Water	Yes	6.3-1
43	MIII-3	SI	S.I. to R.C. System Hot Leg Loops #2 & #3	4	55	8	Water	Yes	6.3-1
44	MIII-4	SI	S.I. To R.C. System Hot Leg Loops #1 & #4	4	55	8	Water	Yes	6.3.1 (Sh. 3)
45	MIII-5	SI	S.I. To R.C. System Cold Leg Loops #1, #2, #3 & #4	4	55	33	Water	Yes	6.3-1
46	MIII-6	CS	Charging Line to Regenerative Heat Exchanger	3	55	25	Water	No	9.3-10
47	MIII-7	CS	Seal Injection to R.C. Pump (Loop #1)	2	55	15	Water	No	9.3-10
48	MIII-8	CS	Seal Injection to R.C. Pump (Loop #2)	2	55	15	Water	No	9.3-10
49	MIII-9	CS	Seal Injection to R.C. Pump (Loop #3)	2	55	15	Water	No	9.3-10
50	MIII-10	CS	Seal Injection to R.C. Pump (Loop #4)	2	55	15	Water	No	9.3-10
51	MIII-11	CS	Seal Water Return And Excess Letdown	2	55	24	Water	No	9.3-10
52	MIII-12	WP	R.C.D.T Heat Exchanger To Waste Hold Up Tank	3	56	27	Water	No	11.2-2
52a	MIII-12	WP	Penetration Thermal Relief	3/4	56	27	Water	No	11.2-2
53	MIII-13	-	Spare	10	50	-	-	-	-
54	MIII-14	CT	Containment Spray To Spray Header (TR. B)	16	56	25	Water	Yes	6.2.2-1

TABLE 6.2.4-1
CONTAINMENT ISOLATION VALVING APPLICATION

(Sheet 6 of 11)

Item	Penetration Number	System	Line or Service	Line Size (Inches)	NRC General Design Criterion or Reg. Guide Met	Isolation Valving Arrangement (Fig. 6.2.4-1)	Fluid Contained	Engineered Safeguard Feature	FSAR Figure Number
55	MIII-15	CT	Containment Spray to Spray Header (TR. A)	16	56	25	Water	Yes	6.2.2-1
56	MIII-16	SF	Refueling Water Purification to Refueling Cavity	4	56	14	Air[(a)]	No	9.1-13
57	MIII-17	LT	Containment Leak Rate Test	10	56	31	Air	No	9.4-6
58	MIII-18	VA	Hydrogen Purge Supply	12	56	20	Air	No	9.4-6
59	MIII-19	VA	Hydrogen Purge Exhaust	12	56	21	Air	No	9.4-6
60	MIII-20	DD	Demineralized Water Supply	3	56	5	Water	No	9.2-5
60a	MIII-20	DD	Penetration Thermal Relief	3/4	56	5	Water	No	9.2-5
61	MIII-21	VD	Containment Sump Pump Discharge	4	56	22	Water	No	9.3-5
61a	MIII-21	VD	Penetration Thermal Relief	3/4	56	22	Water	No	9.3-5
62	MIII-22	CI	Instrument Air To Containment	3	56	7	Air	No	9.3-1
63	MIII-23	SI	R.H.R To Hot Leg Loops #2& #3	10	55	8	Water	Yes	6.3-1 (Sh. 3)
64	MIII-24	-	Spare	12	50	-	-	-	-
65	MIII-25	-	Spare	12	50	-	-	-	-
66	MIII-26	-	Spare	12	50	-	-	-	-
67	MIII-27	SF	Refueling Cavity To Refueling Water Purification Pump	4	56	14	Air[(a)]	No	9.1-13
68	MIII-28	-	Spare	12	50	-	-	-	-
69	MIII-29	-	Spare	12	50	-	-	-	-
70	MIII-30	LT	Containment Leak Rate Test Pressurization	12	56	31	Air	No	9.4-6

TABLE 6.2.4-1
CONTAINMENT ISOLATION VALVING APPLICATION

(Sheet 7 of 11)

Item	Penetration Number	System	Line or Service	Line Size (Inches)	NRC General Design Criterion or Reg. Guide Met	Isolation Valving Arrangement (Fig. 6.2.4-1)	Fluid Contained	Engineered Safeguard Feature	FSAR Figure Number
71	MIII-31	SF	Refueling Cavity Skimmer Pump Discharge (System no longer used)	3	56	14	Air	No	9.1-13
72	MIII-32	-	Spare	12	50	-	-	-	-
73	MIV-1(a)	MS	Sample From Steam Generator #1	3/4	57	35	Sat. Water	No	10.3-1
74	MIV-1(b)	PS	R.C. Sample From Hot Legs	3/8	55	29	Sat. Water	No	9.3-4
74a	MIV-1(b)	PS	Penetration Thermal Relief	3/4	55	29	Sat. Water	No	9.3-4
75	MIV-1(c)	-	Spare	2	50	-	-	-	-
76	MIV-2(a)	MS	Sample From Steam Generator #2	3/4	57	35	Sat. Water	No	10.3-1
77	MIV-2(b)	PS	Pressurizer Liquid Space Sample	3/4	55	1	Sat. Water	No	9.3-4
77a	MIV-2(b)	PS	Penetration Thermal Relief	3/4	55	1	Sat. Water	No	9.3-4
78	MIV-2(c)	PS	Pressurizer Steam Space Sample	3/4	55	1	Steam/Water	No	9.3-4
78a	MIV-2(c)	PS	Penetration Thermal Relief	3/4	55	1	Steam/Water	No	9.3-4
79	MIV-3(a)	MS	Sample From Steam Generator #3	3/4	57	35	Sat. Water	No	10.3-1
80	MIV-3(b)	PS	Sample From Accumulators	3/4	55	30	Water	No	9.3-4
80a	MIV-3(b)	PS	Penetration Thermal Relief	3/4	55	30	Water	No	9.3-4
81	MIV-3(c)	WP	RC Pass Sample Discharge to RCDT	3/4	55	43	Water	No	11.2-2
81a	MIV-3(c)	WP	Penetration Thermal Relief	3/4	55	26	Water	No	11.2-2
82	MIV-4(a)	MS	Sample From Steam Generator #4	3/4	57	35	Sat. Water	No	10.3-1
83	MIV-4(b)	SI	Accumulator Test & Fill	3/4	55	6	Water	No	6.3-1
83a	MIV-4(b)	SI	Penetration Thermal Relief	3/4	55	6	Water	No	6.3-1
84	MIV-4(c)	PS	Containment Air PASS Return	1	56	34	Air	No	9.4-6
85	MIV-5(a)	-	Spare	1	50	-	-	-	-
86	MIV-5(b)	-	Spare	2	50	-	-	-	-

TABLE 6.2.4-1
CONTAINMENT ISOLATION VALVING APPLICATION

(Sheet 8 of 11)

Item	Penetration Number	System	Line or Service	Line Size (Inches)	NRC General Design Criterion or Reg. Guide Met	Isolation Valving Arrangement (Fig. 6.2.4-1)	Fluid Contained	Engineered Safeguard Feature	FSAR Figure Number
87	MIV-5(c)	-	Spare	2	50	-	-	-	-
88	MIV-6(a)	-	Spare	1	50	-	-	-	-
89	MIV-6(b)	-	Spare	1	50	-	-	-	-
90	MIV-6(c)	-	Spare	2	50	-	-	-	-
91	MIV-7(a)	-	Spare	1	50	-	-	-	-
92	MIV-7(b)	ESFAS	Containment Press. Sensing PT-937/PT-938	1/2	1.11	10	Hydraulic Fluid	Yes	9.4-6
93	MIV-7(c)	-	Spare	2	50	-	-	-	-
94	MIV-8(a)	RM	Radiation Monitoring Sample	1	56	3	Air	No	9.4-6
95	MIV-8(b)	ESFAS	Containment Press. Sensing PT-936/PT-939	1/2	1.11	10	Hydraulic Fluid	Yes	9.4-6
96	MIV-8(c)	-	Spare	N/A	50	-	-	-	-
97	MIV-9(a)	PS	Containment Air PASS Inlet	1	56	3	Air	No	9.4-6
98	MIV-9(b)	ESFAS	Containment Press. Sensing PT-935	1/2	1.11	10	Hydraulic Fluid	Yes	9.4-6
99	MIV-9(c)	-	Spare	2	50	-	-	-	-
100	MIV-10(a)	PS	Containment Air PASS Inlet	1	56	3	Air	No	9.4-6
101	MIV-10(b)	ESFAS	Containment Pressure Sensing PT-934	1/2	1.11	10	Hydraulic Fluid	Yes	9.4-6
102	MIV-10(c)	RM	Radiation Monitoring Sample Return	1	56	34	Air	No	9.4-6
103	MIV-11(a)	-	Spare	1	50	-	-	-	-
104	MIV-11(b)	SI	N_2 Supply To Accumulators	1	56	7	Nitrogen	No	6.3-1
105	MIV-11(c)	WP	H_2 Supply to R.C. Drain Tank	3/4	56	13	Hydrogen	No	11.2-2
106	MIV-12(a)	-	Spare	2	50	-	-	-	-

TABLE 6.2.4-1
CONTAINMENT ISOLATION VALVING APPLICATION

(Sheet 9 of 11)

Item	Penetration Number	System	Line or Service	Line Size (Inches)	NRC General Design Criterion or Reg. Guide Met	Isolation Valving Arrangement (Fig. 6.2.4-1)	Fluid Contained	Engineered Safeguard Feature	FSAR Figure Number
107	MIV-12(b)	-	Spare	2	50	-	-	-	-
108	MIV-12(c)	-	Spare	2	50	-	-	-	-
109	MV-1	VA	Containment Purge Air Supply	48	56	18	Air	No	9.4-6
110	MV-2	VA	Containment Purge Air Exhaust	48	56	19	Air	No	9.4-6
111	MV-3	CC	CCW Supply To Excess Letdown & R.C. Drain Tank Heat Exchanger	4	57	32	Water	No	9.2-3
112	MV-4	CC	CCW Return From Excess Letdown & R.C. Drain Tank Heat Exchanger	4	57	12	Water	No	9.2-3
113	MV-5	CA	Service Air to Containment	3	56	7	Air	No	9.3-1
114	MV-6	CC	Containment CCW Drain Tank Pumps Discharge	2	56	26	Water	No	9.2-3
114a	MV-6	CC	Penetration Thermal Relief	3/4	56	26	Water	No	9.2-3
115	MV-7	LT	Containment Leak Rate Test Pressure Sensing	8	56	38	Air	No	9.4-6
116	MV-8	RC	Nitrogen Supply to PRT	1	56	13	Nitrogen	No	5.1-1
117	MV-9	CC	CCW Return From R.C.P.'s Motors	8	56	24	Water	No	9.2-3
118	MV-10	CC	CCW Supply to R.C.P.'s Motors	10	56	25	Water	No	9.2-3
119	MV-11	CC	CCW Return From R.C.P.'s Thermal Barrier	4	56	24	Water	No	9.2-3
120	MV-12	CH	Chilled Water Supply to Containment Coolers	6	56	25	Water	No	9.4-11
120a	MV-12	CH	Penetration Thermal Relief	3/4	56	25	Water	No	9.4-11
121	MV-13	CH	Chilled Water Return From Containment Coolers	6	56	28	Water	No	9.4-11
121a	MV-13	CH	Penetration Thermal Relief	3/4	56	28	Water	No	9.4-11
122	MV-14	VA	Containment Pressure Relief	18	56	19	Air	No	9.4-6

TABLE 6.2.4-1
CONTAINMENT ISOLATION VALVING APPLICATION

(Sheet 10 of 11)

Item	Penetration Number	System	Line or Service	Line Size (Inches)	NRC General Design Criterion or Reg. Guide Met	Isolation Valving Arrangement (Fig. 6.2.4-1)	Fluid Contained	Engineered Safeguard Feature	FSAR Figure Number
123	MV-15	-	Maintenance Penetration	1	56	31	Air	No	9.4-6
124	MV-16	FP	Fire Protection System Isolation	4	56	39	Air[(b)]	No	9.5-48
125	MS-1	SI	Containment Recirculation	16	56	2	Water	Yes	6.3-1
			Sump To R.H.R. Pump (TR. A) Thermal Relief	3/4	56	2	Water	No	
126	MS-2	SI	Containment Recirculation	16	56	2	Water	Yes	6.3-1
			Sump to R.H.R. Pump (TR. B) Thermal Relief	3/4	56	2	Water	No	
127	MS-3	CT	Containment Recirculation	16	56	2	Water	Yes	6.2.2-1
			Sump to Spray Pumps (TR. A) Thermal Relief	3/4	56	2	Water	No	
128	MS-4	CT	Containment Recirculation	16	56	2	Water	Yes	6.2.2-1
			Sump To Spray Pumps (TR. B) Thermal Relief	3/4	56	2	Water	No	
129	MS-5	SF	Fuel Transfer Tube	20	50	23	Air[(a)]	No	9.1-13 6.2.6-1
130	Unit 1								
	Personnel Airlock Hydraulics	BS/CB	Airlock Hydraulic System	3/4	57	40	Hydraulic	No	3.8-22
131	Unit 1								
	Personnel Airlock	BS/CB	Hydraulically Operated Airlock Equalization	3	56	41	Air	No	3.8-22
131a	Unit 1								
	Personnel Airlock	BS/CB	Manual Airlock Equalization	3/4	56	41	Air	No	3.8-22

TABLE 6.2.4-1
CONTAINMENT ISOLATION VALVING APPLICATION

(Sheet 11 of 11)

Item	Penetration Number	System	Line or Service	Line Size (Inches)	NRC General Design Criterion or Reg. Guide Met	Isolation Valving Arrangement (Fig. 6.2.4-1)	Fluid Contained	Engineered Safeguard Feature	FSAR Figure Number
132	Emergency Airlock	BS/CB	Manual Airlock Equalization	2	56	42	Air	No	3.8-23
133	Unit 2								
	Personnel Airlock Hydraulics	BS/CB	Airlock Hydraulic System	3/4	56	44	Hydraulic	No	3.8-23
134	Unit 2								
	Personnel Airlock	BS/CB	Hydraulically Operated Airlock Equalization	3	56	45	Air	No	3.8-22
134a	Unit 2 Personnel Airlock	BS/CB	Manual Airlock Equalization	3/4	56	45	Air	No	3.8-23

a) Fluid: Air During Normal Operation, Water During Refueling - kThe valve (SF-0001) associated with this penetration (ITEM 129) is Open during Refueling. Valve SF-0001 is a non-safety related valve that has no direct Containment Isolation function during MODES 1-4. This valve is Normally Closed in MODES 1-4. The valve may be opened in MODES 1-4 except when the Fuel Transfer Canal is flooded to maintain the fuel Transfer Flange as Leak Rate Tested. Opening the valve allows for equipment testing and to support preparations for Refueling Outages.

b) This penetration is drained and purged with nitrogen prior to plant operation.

TABLE 6.2.4-2
CONTAINMENT ISOLATION VALVING APPLICATION (Note 8)

(Sheet 1 of 13)

Item	Isolation Valve No (Note 6)	Location in Relation to Containment	Type of Leakage Rate Test	Direction of Test (Note 10)	Length of Pipe U1/U2 to Outermost Isolation Valve (ft)	Valve Type/Operator	Method of Actuation Primary	Secondary
1	HV-2333A	Outside	Note 1	N/A	40'/38'-1"	Y - Globe/Hydr. N_2 Actuator	Auto close	Remote Manual
2	HV-2333B	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
3	HV-2409	Outside	Note 1	N/A	-	Globe/Air	Auto close	Remote Manual
4	HV-2452-2	Outside	Note 1	N/A	-	Globe/Air	Remote Manual	N/A
	MS-101 (Note 16)	Outside	Note 1	N/A	-	Gate/Gear	Local Manual	N/A
4a	MS-711	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
5	PV-2325	Outside	Note 1	N/A	-	Globe/Air	Remote Manual	N/A
5a	MS-390	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
5b	MS-021	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
	MS-022	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
	MS-023	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
	MS-024	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
	MS-025	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
6	HV-2334A	Outside	Note 1	N/A	38'/35'-9"	Y - Globe/Hydr. N_2 Actuator	Auto close	Remote Manual
7	HV-2334B	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
8	HV-2410	Outside	Note 1	N/A	-	Globe/Air	Auto close	Remote Manual
9	PV-2326	Outside	Note 1	N/A	-	Globe/Air	Remote Manual	N/A
9a	MS-387	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
9b	MS-058	Outside	Note 1	N/A	-	Safety Relief	Self Actuated	N/A
	MS-059	Outside	Note 1	N/A	-	Safety Relief	Self Actuated	N/A
	MS-060	Outside	Note 1	N/A	-	Safety Relief	Self Actuated	N/A
	MS-061	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
	MS-062	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
10	HV-2335A	Outside	Note 1	N/A	40'/38'-5"	Y - Globe/Hydr. N_2 Actuator	Auto close	Remote Manual

TABLE 6.2.4-2
CONTAINMENT ISOLATION VALVING APPLICATION (Note 8)

(Sheet 2 of 13)

Item	Isolation Valve No (Note 6)	Location in Relation to Containment	Type of Leakage Rate Test	Direction of Test (Note 10)	Length of Pipe U1/U2 to Outermost Isolation Valve (ft)	Valve Type/Operator	Method of Actuation Primary	Secondary
11	HV-2335B	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
12	HV-2411	Outside	Note 1	N/A	-	Globe/Air	Auto close	Remote Manual
13	PV-2327	Outside	Note 1	N/A	-	Globe/Air	Remote Manual	N/A
13a	MS-384	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
13b	MS-093	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
	MS-094	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
	MS-095	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
	MS-096	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
	MS-097	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
14	HV-2336A	Outside	Note 1	N/A	38'/35'-9"	Y - Globe/Hydr. N_2 Actuator	Auto close	Remote Manual
15	HV-2336B	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
16	HV-2412	Outside	Note 1	N/A	-	Globe/Air	Auto close	Remote Manual
17	HV-2452-1	Outside	Note 1	N/A	-	Globe/Air	Remote Manual	N/A
	MS-128 (Note 16)	Outside	Note 1	N/A	-	Gate/Gear	Local Manual	N/A
17a	MS-712	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
18	PV-2328	Outside	Note 1	N/A	-	Globe/Air	Remote Manual	N/A
18a	MS-393	Outside	Note 1	N/A	-	Globe/Manual	Local	N/A
18b	MS-129	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
	MS-130	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
	MS-131	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
	MS-132	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
	MS-133	Outside	Note 1	N/A	-	Safety Relief	Self-Actuated	N/A
19	HV-2134	Outside	Note 1	N/A	10'/12'-10"	Gate/Hydr. N_2 Actuator	Auto close	Remote Manual
20	FW-0116	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
20a	HV-2491A	Outside	Note 1	N/A	50'/48'-9"	Gate/Motor	Remote Manual	Local Manual
	HV-2491B	Outside	Note 1	N/A	50'/51'-9"	Gate/Motor	Remote Manual	Local Manual

TABLE 6.2.4-2
CONTAINMENT ISOLATION VALVING APPLICATION (Note 8)

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Item	Isolation Valve No (Note 6)	Location in Relation to Containment	Type of Leakage Rate Test	Direction of Test (Note 10)	Length of Pipe U1/U2 to Outermost Isolation Valve (ft)	Valve Type/Operator	Method of Actuation Primary	Secondary
20b	FW-106	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
20c	2-FV-2193	Outside	Note 1	N/A	30'-9"	Globe/Air	Auto close	Remote Manual
20d	HV-2185	Outside	Note 1	N/A	12'-7"/11'-3"	Globe/Air	Auto close	Remote Manual
21	HV-2135	Outside	Note 1	N/A	10'/11'-8"	Gate/Hydr. N_2 Actuator	Auto close	Remote Manual
22	FW-0113	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
22a	HV-2492A	Outside	Note 1	N/A	50'/51'-8"	Gate/Motor	Remote Manual	Local Manual
	HV-2492B	Outside	Note 1	N/A	50'/54'-7"	Gate/Motor	Remote Manual	Local Manual
22b	FW-104	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
22c	2-FV-2194	Outside	Note 1	N/A	30'-9"	Globe/Air	Auto close	Remote Manual
22d	HV-2186	Outside	Note 1	N/A	12'-8"/11'-8"	Globe/Air	Auto close	Remote Manual
23	HV-2136	Outside	Note 1	N/A	10'/15'-4"	Gate/Hydr. N_2 Actuator	Auto close	Remote Manual
24a	HV-2493A	Outside	Note 1	N/A	50'/50'-5"	Gate/Motor	Remote Manual	Local Manual
	HV-2493B	Outside	Note 1	N/A	50'/53'-5"	Gate/Motor	Remote Manual	Local Manual
24b	FW-102	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
24c	2-FV-2195	Outside	Note 1	N/A	33'-0"	Globe/Air	Auto close	Remote Manual
24d	HV-2187	Outside	Note 1	N/A	12'-8"/11'-9"	Globe/Air	Auto close	Remote Manual
25	HV-2137	Outside	Note 1	N/A	10'/15'-3"	Gate/Hydr. N_2 Actuator	Auto close	Remote Manual
26	-	-	-	-	-	-	-	-
26a	HV-2494A	Outside	Note 1	N/A	50'/50'-4"	Gate/Motor	Remote Manual	Local Manual
	HV-2494B	Outside	Note 1	N/A	50'/53'8"	Gate/Motor	Remote Manual	Local Manual
26b	FW-108	Outside	Note 1	N/A	-	Globe/Manual	Local Manual	N/A
26c	2-FV-2196	Outside	Note 1	N/A	33'-1"	Globe/Air	Auto close	Remote Manual
26d	HV-2188	Outside	Note 1	N/A	12'-8"/11'-9"	Globe/Air	Auto close	Remote Manual
27	HV-2399	Outside	Note 1	N/A	17'/16'-6"	Globe/Air	Auto close	Remote Manual
28	HV-2398	Outside	Note 1	N/A	17'/16'-2"	Globe/Air	Auto close	Remote Manual

TABLE 6.2.4-2
CONTAINMENT ISOLATION VALVING APPLICATION (Note 8)

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Item	Isolation Valve No (Note 6)	Location in Relation to Containment	Type of Leakage Rate Test	Direction of Test (Note 10)	Length of Pipe U1/U2 to Outermost Isolation Valve (ft)	Valve Type/Operator	Method of Actuation Primary	Secondary
29	HV-2397	Outside	Note 1	N/A	17'/16'-0"	Globe/Air	Auto close	Remote Manual
30	HV-2400	Outside	Note 1	N/A	17'/16'-8"	Globe/Air	Auto close	Remote Manual
31	-	-	A	N/A	-	-	-	-
32	8152	Outside	C	YES	7'/7'-7"	Globe/Air	Auto close	Remote Manual
	8160	Inside	C	YES	-	Globe/Air	Auto close	Remote Manual
33	8701B	Inside	Note 17	N/A	N/A	Gate/Motor	Remote Manual	Remote Manual
	8708B	Inside	Note 17	N/A	N/A	Relief	Self-Actuated	N/A
34	8701A	Inside	Note 17	N/A	N/A	Gate/Motor	Remote Manual	Local Manual
	8708A	Inside	Note 17	N/A	N/A	Relief	Self-Actuated	N/A
35	8809A	Outside	Note 3	N/A	8'/9'-11"	Gate/Motor	Remote Manual	Local Manual
	8818A	Inside	Note 11	N/A	-	Check	Self-Actuated	N/A
	8818B	Inside	Note 11	N/A	-	Check	Self-Actuated	N/A
	8890A	Inside	Note 11	N/A	-	Globe/Air	Auto close	Remote Manual
36	8809B	Outside	Note 3	N/A	3'/5'-9"	Gate/Motor	Remote Manual	Local Manual
	8818C	Inside	Note 11	N/A	-	Check	Self-Actuated	N/A
	8818D	Inside	Note 11	N/A	-	Check	Self-Actuated	N/A
	8890B	Inside	Note 11	N/A	-	Globe/Air	Auto close	Remote Manual
37	-	-	A	N/A	-	-	-	-
38	-	-	A	N/A	-	-	-	-
39	-	-	A	N/A	-	-	-	-
40a	N/A	N/A	B	N/A	N/A	N/A	N/A	N/A
40b	N/A	N/A	B	N/A	N/A	N/A	N/A	N/A
40c	N/A	N/A	B	N/A	N/A	N/A	N/A	N/A
41	8046	Inside	C	YES	-	Check	Self-Actuated	N/A
	8047	Outside	C	YES	16'/18'-1"	Diaphragm/Air	Auto close	Remote Manual
41a	RC-036	Outside	C	YES	-	Relief	Self-Actuated	N/A

TABLE 6.2.4-2
CONTAINMENT ISOLATION VALVING APPLICATION (Note 8)

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Item	Isolation Valve No (Note 6)	Location in Relation to Containment	Type of Leakage Rate Test	Direction of Test (Note 10)	Length of Pipe U1/U2 to Outermost Isolation Valve (ft)	Valve Type/Operator	Method of Actuation Primary	Secondary
42	8815	Inside	Note 2	N/A	-	Check	Self-Actuated	N/A
	8801A	Outside	Note 7	N/A	13'/16'-1"	Gate/Motor	Remote Manual	N/A
	8801B	Outside	Note 7	N/A	13'/16'-1"	Gate/Motor	Remote Manual	N/A
	8843	Inside	Note 2	N/A	-	Globe/Air	Auto close	Remote Manual
43	8802A	Outside	Note 12	N/A	11'/13'-0"	Gate/Motor	Remote Manual	Local Manual
	SI-8905B	Inside	Note 12	N/A	-	Check	Self-Actuated	N/A
	SI-8905C	Inside	Note 12	N/A	-	Check	Self-Actuated	N/A
	8881	Inside	Note 12	N/A	-	Globe/Air	Auto close	Remote Manual
44	8802B	Outside	Note 12	N/A	12'/13'-9"	Gate/Motor	Remote Manual	Local Manual
	SI-8905A	Inside	Note 12	N/A	-	Check	Self-Actuated	N/A
	SI-8905D	Inside	Note 12	N/A	-	Check	Self-Actuated	N/A
	8824	Inside	Note 12	N/A	-	Globe/Air	Auto close	Remote Manual
45	8835	Outside	Note 13	N/A	16'/19'-1"	Gate/Motor	Remote Manual	Local Manual
	SI-8819A	Inside	Note 13	N/A	-	Check	Self-Actuated	N/A
	SI-8819B	Inside	Note 13	N/A	-	Check	Self-Actuated	N/A
	SI-8819C	Inside	Note 13	N/A	-	Check	Self-Actuated	N/A
	SI-8819D	Inside	Note 13	N/A	-	Check	Self-Actuated	N/A
	8823	Inside	Note 13	N/A	-	Globe/Air	Auto close	Remote Manual
46	8105	Outside	C	YES	3'/10'-7"	Gate/Motor	Auto close	Remote Manual
	8381	Inside	C	YES	-	Check	Self-Actuated	N/A
47	CS-8368A	Inside	Note 4	N/A	-	Check	Self-Actuated	N/A
	8351A	Outside	Note 4	N/A	6'/15'-7"	Globe/Motor	Remote Manual	Local Manual
48	CS-8368B	Inside	Note 4	N/A	-	Check	Self-Actuated	N/A
	8351B	Outside	Note 4	N/A	7'/9'-9"	Globe/Motor	Remote Manual	Local Manual
49	CS-8368C	Inside	Note 4	N/A	-	Check	Self-Actuated	N/A
	8351C	Outside	Note 4	N/A	2'/11'-11"	Globe/Motor	Remote Manual	Local Manual
50	CS-8368D	Inside	Note 4	N/A	-	Check	Self-Actuated	N/A
	8351D	Outside	Note 4	N/A	10'/10'-3"	Globe/Motor	Remote Manual	Local Manual

TABLE 6.2.4-2
CONTAINMENT ISOLATION VALVING APPLICATION (Note 8)

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Item	Isolation Valve No (Note 6)	Location in Relation to Containment	Type of Leakage Rate Test	Direction of Test (Note 10)	Length of Pipe U1/U2 to Outermost Isolation Valve (ft)	Valve Type/Operator	Method of Actuation Primary	Secondary
51	8100	Outside	C	YES	7'/7'-1"	Globe/Motor	Auto close	Remote Manual
	8112	Inside	C	YES	-	Globe/Motor	Auto close	Remote Manual
	CS-8180	Inside	C	YES	-	Check	Self-Actuated	N/A
52	7136	Inside	C	YES	-	Diaph./Air	Auto close	Remote Manual
	LCV-1003	Outside	C	YES	30'/23'-11"	Globe/Air	Auto close	Remote Manual
	7135	Outside	C	YES	30'/24'-2"	Diaph./Manual	Local Manual	N/A
52a	WP-7176	Outside	C	YES	-	Relief	Self-Actuated	N/A
53	-	-	A	N/A	-	-	-	-
54	HV-4777	Outside	Note 3	N/A	15'/16'-7"	Gate/Motor	Remote Manual	N/A
	CT-145	Inside	Note 3	N/A	-	Check	Self-Actuated	N/A
55	HV-4776	Outside	Note 3	N/A	9'/16'-9"	Gate/Motor	Remote Manual	N/A
	CT-142	Inside	Note 3	N/A	-	Check	Self-Actuated	N/A
56	SF-011	Outside	C	YES	11'/18'-6"	Diaphragm/Man.	Local Manual	N/A
	SF-012	Inside	C	YES	-	Diaphragm/Man.	Local Manual	N/A
57	N/A	N/A	B	N/A	N/A	N/A	N/A	N/A
58	HV-5542	Outside	C	YES	5'-6"/1'-5"	Butterfly/Motor	Auto close	Remote Manual
	HV-5543	Inside	C	NO	-	Butterfly/Motor	Auto close	Remote Manual
	HV-5563	Inside	C	NO	-	Butterfly/Motor	Auto close	Remote Manual
59	HV-5540	Outside	C	YES	5'-6"/5'-10"	Butterfly/Motor	Auto close	Remote Manual
	HV-5541	Inside	C	NO	-	Butterfly/Motor	Auto close	Remote Manual
	HV-5562	Inside	C	NO	-	Butterfly/Motor	Auto close	Remote Manual
60	HV-5365	Outside	C	YES	12'/14'-8"	Globe/Air	Auto close	Remote Manual
	HV-5366	Inside	C	YES	-	Globe/Air	Auto close	Remote Manual
60a	DD-430	Outside	C	YES	-	Relief	Self-Actuated	N/A
61	HV-5157	Outside	C	YES	14'/16'-2"	Diaphragm/Air	Auto close	Remote Manual
	HV-5158	Inside	C	NO	-	Diaphragm/Air	Auto close	Remote Manual

TABLE 6.2.4-2
CONTAINMENT ISOLATION VALVING APPLICATION (Note 8)

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Item	Isolation Valve No (Note 6)	Location in Relation to Containment	Type of Leakage Rate Test	Direction of Test (Note 10)	Length of Pipe U1/U2 to Outermost Isolation Valve (ft)	Valve Type/Operator	Method of Actuation Primary	Secondary
61a	1VD-907 (2VD-0896)	Outside	C	YES	-	Relief	Self-Actuated	N/A
62	HV-3487	Outside	C	YES	14'/17'-3"	Globe/Air	Auto close	Remote Manual
	CI-030	Inside	C	YES	-	Check	Self-Actuated	N/A
63	8840	Outside	Note 3	N/A	26'/27'-8"	Gate/Motor	Remote Manual	Local Manual
	8825	Inside	Note 14	N/A	-	Globe/Air	Auto close	Remote Manual
	8841A	Inside	Note 14	N/A	-	Check	Self-Actuated	N/A
	8841B	Inside	Note 14	N/A	-	Check	Self-Actuated	N/A
64	-	-	A	N/A	-	-	-	-
65	-	-	A	N/A	-	-	-	-
66	-	-	A	N/A	-	-	-	-
67	SF-021	Inside	C	YES	-	Diaphragm/Man.	Local Manual	N/A
	SF-022	Outside	C	YES	11'/8'-2"	Diaphragm/Man.	Local Manual	N/A
68	-	-	A	-	-	-	-	-
69	-	-	A	-	-	-	-	-
70	N/A	N/A	B	N/A	N/A	N/A	N/A	N/A
71	1SF-053 (2SF-055)	Inside	C	YES	-	Diaphragm/Man.	Local Manual	N/A
	1SF-054 (2SF-056)	Outside	C	YES	7'/4'-10"	Diaphragm/Man.	Local Manual	N/A
72	-	-	A	N/A	-	-	-	-
73	HV-2405	Outside	Note 1	N/A	5'-3"/11'-8"	Globe/Air	Auto close	Remote Manual
74	HV-4170	Outside	C	YES	6'-0"/8'-0"	Angle/Air	Auto close	Remote Manual
	HV-4168	Inside	C	YES	-	Angle/Air	Auto close	Remote Manual
	HV-4169	Inside	C	YES	-	Angle/Air	Auto close	Remote Manual
74a	PS-503	Outside	C	YES	-	Relief	Self-Actuated	N/A
75	-	-	A	N/A	-	-	-	-
76	HV-2406	Outside	Note 1	N/A	5'-6"/12'-11"	Globe/Air	Auto close	Remote Manual

TABLE 6.2.4-2
CONTAINMENT ISOLATION VALVING APPLICATION (Note 8)

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Item	Isolation Valve No (Note 6)	Location in Relation to Containment	Type of Leakage Rate Test	Direction of Test (Note 10)	Length of Pipe U1/U2 to Outermost Isolation Valve (ft)	Valve Type/Operator	Method of Actuation Primary	Secondary
77	HV-4167	Outside	C	YES	3'-8"/8'-1"	Angle/Air	Auto close	Remote Manual
	HV-4166	Inside	C	YES	-	Angle/Air	Auto close	Remote Manual
77a	PS-501	Outside	C	YES	-	Relief	Self-Actuated	N/A
78	HV-4176	Outside	C	YES	4'-8"/11'-10"	Angle/Air	Auto close	Remote Manual
	HV-4165	Inside	C	YES	-	Angle/Air	Auto close	Remote Manual
78a	PS-502	Outside	C	YES	-	Relief	Self-Actuated	N/A
79	HV-2407	Outside	Note 1	N/A	4'-9"/7'-6"	Globe/Air	Auto close	Remote Manual
80	HV-4175	Outside	C	YES	5'-8"/10'-11"	Angle/Air	Auto close	Remote Manual
	HV-4171	Inside	C	YES	-	Angle/Air	Auto close	Remote Manual
	HV-4172	Inside	C	YES	-	Angle/Air	Auto close	Remote Manual
	HV-4173	Inside	C	YES	-	Angle/Air	Auto close	Remote Manual
	HV-4174	Inside	C	YES	-	Angle/Air	Auto close	Remote Manual
80a	PS-500	Outside	C	YES	-	Relief	Self-Actuated	N/A
81	HV-7311	Outside	C	YES	15'/17'-3"	Globe/Air	Auto close	Remote Manual
	HV-7312	Inside	C	YES	-	Globe/Air	Auto close	Remote Manual
81a	WP-7177	Outside	C	YES	-	Relief	Self-Actuated	N/A
82	HV-2408	Outside	Note 1	N/A	6'-3"/12'-6"	Globe/Air	Auto close	Remote Manual
83	8871	Inside	C	YES	-	Globe/Air	Auto close	Remote Manual
	8888	Outside	C	YES	21'/22'-7"	Globe/Air	Auto close	Remote Manual
	8964	Outside	C	YES	15'/19'-0"	Globe/Air	Auto close	Remote Manual
	SI-8961	Outside	Note 5	N/A	15'/16'-6"	Globe/Manual	Manual	N/A
83a	1SI-8972 (2SI-8983)	Outside	C	YES	-	Relief	Self-Actuated	N/A
84	HV-5556	Outside	C	YES	5'-9"/5'-9"	Globe/Solenoid	Auto close	Remote Manual
	HV-5557	Inside	C	YES	-	Globe/Solenoid	Auto close	Remote Manual
85	-	-	A	N/A	-	-	-	-
86	-	-	A	N/A	-	-	-	-
87	-	-	A	N/A	-	-	-	-

TABLE 6.2.4-2
CONTAINMENT ISOLATION VALVING APPLICATION (Note 8)

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Item	Isolation Valve No (Note 6)	Location in Relation to Containment	Type of Leakage Rate Test	Direction of Test (Note 10)	Length of Pipe U1/U2 to Outermost Isolation Valve (ft)	Valve Type/Operator	Method of Actuation Primary	Secondary
88	-	-	A	N/A	-	-	-	-
89	-	-	A	N/A	-	-	-	-
90	-	-	A	N/A	-	-	-	-
91	-	-	A	N/A	-	-	-	-
92	None	-	A	N/A	-	N/A	-	-
93	-	-	A	N/A	-	-	-	-
94	HV-5544	Outside	C	YES	4'-0"/3'-2"	Globe/Solenoid	Auto close	Remote Manual
	HV-5545	Inside	C	YES	-	Globe/Solenoid	Auto close	Remote Manual
95	None	-	A	N/A	-	N/A	-	-
96	-	-	A	N/A	-	-	-	-
97	HV-5558	Outside	C	YES	5'-0"/3'-8"	Globe/Solenoid	Auto close	Remote Manual
	HV-5559	Inside	C	YES	-	Globe/Solenoid	Auto close	Remote Manual
98	None	-	A	N/A	-	N/A	-	-
99	-	-	A	N/A	-	-	-	-
100	HV-5560	Outside	C	YES	4'-0"/4'-9"	Globe/Solenoid	Auto close	Remote Manual
	HV-5561	Inside	C	YES	-	Globe/Solenoid	Auto close	Remote Manual
101	None	-	A	N/A	-	N/A	-	-
102	HV-5546	Outside	C	YES	2'0"/2'-11"	Globe/Solenoid	Auto close	Remote Manual
	HV-5547	Inside	C	YES	-	Globe/Solenoid	Auto close	Remote Manual
103	-	-	A	N/A	-	-	-	-
104	8880	Outside	C	YES	28'/28'-2"	Globe/Air	Auto close	Remote Manual
	SI-8968	Inside	C	YES	-	Check	Self-Actuated	N/A
105	7126	Inside	C	YES	-	Diaphragm/Air	Auto close	Remote Manual
	7150	Outside	C	YES	19'/22'-11"	Diaphragm/Air	Auto close	Remote Manual
106	-	-	A	N/A	-	-	-	-
107	-	-	A	N/A	-	-	-	-
108	-	-	A	N/A	-	-	-	-

TABLE 6.2.4-2
CONTAINMENT ISOLATION VALVING APPLICATION (Note 8)

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Item	Isolation Valve No (Note 6)	Location in Relation to Containment	Type of Leakage Rate Test	Direction of Test (Note 10)	Length of Pipe U1/U2 to Outermost Isolation Valve (ft)	Valve Type/Operator	Method of Actuation Primary	Secondary
109	HV-5536	Outside	C	YES	1'-0"/1'-7"	Butterfly/Air	Auto close	Remote Manual
	HV-5537	Inside	C	NO	-	Butterfly/Air	Auto close	Remote Manual
110	HV-5538	Outside	C	YES	2'/1'-11"	Butterfly/Air	Auto close	Remote Manual
	HV-5539	Inside	C	NO	-	Butterfly/Air	Auto close	Remote Manual
111	HV-4710	Outside	Note 1	N/A	12'/16'-8"	Globe/Air	Auto close	Remote Manual
112	HV-4711	Outside	Note 1	N/A	14'/16'-1"	Globe/Air	Auto close	Remote Manual
113	CA-016	Inside	C	YES	-	Check	Self-Actuated	N/A
	HV-3486	Outside	C	N/A	11'/11'-1"	Globe/Air	Auto close	Remote Manual
114	HV-4725	Inside	C	YES	-	Globe/Air	Auto close	Remote Manual
	HV-4726	Outside	C	YES	11'/11'-1"	Globe/Air	Auto close	Remote Manual
114a	1CC-1067 (2CC-1090)	Outside	C	YES	-	Relief	Self-Actuated	N/A
115	N/A	N/A	B	N/A	N/A	N/A	N/A	N/A
116	8027	Outside	C	YES	25'/4'-1"	Diaphragm/Air	Auto close	Remote Manual
	8026	Inside	C	YES	-	Diaphragm/Air	Auto close	Remote Manual
117	HV-4708	Outside	C	YES	8'/14'-7"	Gate/Motor	Auto close	Remote Manual
	HV-4701	Inside	C	YES	-	Gate/Motor	Auto close	Remote Manual
	CC-629	Inside	C	YES	-	Check	Self-Actuated	N/A
118	HV-4700	Outside	C	YES	18'/12'-7"	Gate/Motor	Auto close	Remote Manual
	CC-713	Inside	C	YES	-	Check	Self-Actuated	N/A
119	HV-4709	Outside	C	YES	18'/19'-1"	Gate/Motor	Auto close	Remote Manual
	HV-4696	Inside	C	YES	-	Gate/Motor	Auto close	Remote Manual
	CC-831	Inside	C	YES	-	Check	Self-Actuated	N/A
120	HV-6084	Outside	C	YES	16'/16'-1"	Gate/Motor	Auto close	Remote Manual
	CH-024	Inside	C	YES	-	Check	Self-Actuated	N/A
120a	1CH-271 (2CH-0281)	Outside	C	YES	-	Relief	Self-Actuated	N/A

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CONTAINMENT ISOLATION VALVING APPLICATION (Note 8)

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Item	Isolation Valve No (Note 6)	Location in Relation to Containment	Type of Leakage Rate Test	Direction of Test (Note 10)	Length of Pipe U1/U2 to Outermost Isolation Valve (ft)	Valve Type/Operator	Method of Actuation Primary	Secondary
121	HV-6082	Outside	C	YES	15'/16'-8"	Gate/Motor	Auto close	Remote Manual
	HV-6083	Inside	C	YES	-	Gate/Motor	Auto close	Remote Manual
121a	1CH-272 (2CH-0282)	Outside	C	YES	-	Relief	Self-Actuated	N/A
122	HV-5548	Outside	C (Note 15)	YES	2'/1'-7"	Butterfly/Air	Auto close	Remote Manual
	HV-5549	Inside	C (Note 15)	NO	-	Butterfly/Air	Auto close	Remote Manual
123	N/A	N/A	B	N/A	N/A	N/A	N/A	N/A
124	HV-4075B	Outside	C	YES	-	Gate/Motor	Auto close	Remote Manual
	HV-4075C	Inside	C	YES	-	Gate/Motor	Auto close	Remote Manual
125	8811A	Outside	Note 9	N/A	6'/7'-5"	Gate/Motor	Remote Manual	Local Manual
	SI-0182	Outside	Note 9	N/A	-	Relief	Self-Actuated	N/A
126	8811B	Outside	Note 9	N/A	6'/6'9"	Gate/Motor	Remote Manual	Local Manual
	SI-0183	Outside	Note 9	N/A	-	Relief	Self-Actuated	N/A
127	HV-4782	Outside	Note 9	N/A	6'/6'-9"	Gate/Motor	Remote Manual	Local Manual
	CT-0309	Outside	Note 9	N/A	-	Relief	Self-Actuated	N/A
128	HV-4783	Outside	Note 9	N/A	6'/7'-5"	Gate/Motor	Remote Manual	Local Manual
	CT-0310	Outside	Note 9	N/A	-	Relief	Self-Actuated	N/A
129	Bellows	N/A	B	N/A	N/A	N/A	N/A	N/A
	Flange	N/A	B	N/A	N/A	N/A	N/A	N/A
130	1BS-0016	Outside	Note 1	N/A	1	Globe/Manual	Local Manual	N/A
	1BS-0017	Outside	Note 1	N/A	1	Globe/Manual	Local Manual	N/A
131	1BS-0030	Inside	C	No	1	Ball/Hydraulic	Local Hydraulic	N/A
	1BS-0025	Inside	C	Yes	1	Ball/Hydraulic	Local Hydraulic	N/A

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CONTAINMENT ISOLATION VALVING APPLICATION (Note 8)

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Item	Isolation Valve No (Note 6)	Location in Relation to Containment	Type of Leakage Rate Test	Direction of Test (Note 10)	Length of Pipe U1/U2 to Outermost Isolation Valve (ft)	Valve Type/Operator	Method of Actuation Primary	Secondary
131a	1BS-0056	Inside	C	No	1	Ball/Manual	Local Manual	N/A
	1BS-0044	Inside	C	No	1	Ball/Manual	Local Manual	N/A
	1BS-0029	Inside	C	Yes	1	Ball/Manual	Local Manual	N/A
	1BS-0015	Outside	C	Yes	1	Ball/Manual	Local Manual	N/A
132	BS-0202	Inside	C	No	1	Ball/Manual	Local Manual	N/A
	BS-0203	Inside	C	Yes	1	Ball/Manual	Local Manual	N/A
133	2BS-0016	Inside	C	No	1	Globe/Manual	Local Manual	N/A
	2BS-0017	Inside	C	No	1	Globe/Manual	Local Manual	N/A
	2BS-0039	Inside	C	Yes	1	Globe/Manual	Local Manual	N/A
	2BS-0040	Inside	C	Yes	1	Globe/Manual	Local Manual	N/A
134	2BS-0030	Inside	C	No	1	Ball/Hydraulic	Local Hydraulic	N/A
	2BS-0025	Outside	C	Yes	1	Ball/Hydraulic	Local Hydraulic	N/A
134a	2BS-0056	Inside	C	No	1	Relief/Spring Closed	Local Manual	N/A
	2BS-0044	Inside	C	No	1	Relief/Spring Closed	Local Manual	N/A
	2BS-0029	Inside	C	Yes	1	Relief/Spring Closed	Local Manual	N/A
	2BS-0015	Outside	C	Yes	1	Relief/Spring Closed	Local Manual	N/A

Notes:

1. These are closed systems which meet the requirements of NUREG-0800, Section 6.2.4, II.6, paragraph o. These valves are therefore not required to be tested.
2. These valves inside containment are part of closed systems outside containment which are in service post-accident at a pressure in excess of containment design pressure and satisfy single active failure criteria. These valves are therefore not required to be tested.
3. These are closed systems outside containment which are in service post-accident and have a water filled loop seal on the containment side of the valves for a period greater than 30 days following the accident. These valves are either open or are closed providing a third barrier to containment leakage. A water seal if maintained both inside and outside containment. These valves are therefore not required to be leakrate tested.
4. These ESF valves are normally open and remain open during post-accident conditions. Post-accident they are continually pressurized in excess of containment pressure from an ESF source which meets the single active failure criteria. These valves are therefore not to be tested.
5. This valve is not required to be leakage tested per 10 CFR 50 Appendix J since the downstream pressure indicator sensing element is dead-ended, and is hydrostatically tested to 1.5 times the design pressure of the pipe, thus providing a leaktight barrier similar to vent and drain connections having capped ends and under administrative controls.

TABLE 6.2.4-2
CONTAINMENT ISOLATION VALVING APPLICATION (Note 8)

(Sheet 13 of 13)

Item	Isolation Valve No (Note 6)	Location in Relation to Containment	Type of Leakage Rate Test	Direction of Test (Note 10)	Length of Pipe U1/U2 to Outermost Isolation Valve (ft)	Valve Type/Operator	Method of Actuation Primary	Secondary

6. Unit 1 and Unit 2 Tag Numbers are generally the same except for the prefix or as otherwise noted.
7. These are parallel ESF valves that are normally closed, but are designed to open during post-accident conditions. Failure of one valve to open will not prevent system pressurization on both sides of both valves in excess of containment pressure. These valves are therefore not required to be tested.
8. Table does not list local vent, drain and test connections as they are a special class of containment isolation valve per FSAR Section 6.2.4.1.3. These valves are locked closed and capped to meet containment isolation criteria if located within the pressure boundary. These valves do not require Type C testing.
9. These penetrations are normally closed and upon initial ESF actuation remain closed with a water seal from the RWST. During the ESF recirculation phases, the RHR and Containment Spray suction side isolation valves are open and supplying water to their respective ESF pumps. Water in the containment sump provides a seal between the containment atmosphere (post-accident) and these valves.
10. "YES" signifies that the isolation valve test pressure is applied in the same direction as the pressure existing when the valve is required to perform its containment isolation function.
    "NO" signifies that the isolation valve test pressure is not applied in the same direction as the pressure existing when the valve is required to perform its safety function.
11. This penetration is an engineered safety feature system supplying RHR pump flow (valves opened) to the cold legs of the RCS during cold leg injection and cold leg recirculation modes of operation. During hot leg recirculation this penetration is not in service (valves closed) but is pressurized by the residual heat removal pumps to a pressure in excess of 1.1 times the containment design pressure. The outside containment motor operated valve and the closed system outside containment provide two boundries in addition to this valve. These valves are therefore not required to be Type C tested.
12. This penetration is an Engineered Safety Feature System supplying SI pump flow (valves opened) to the hot legs of the RCS during hot leg recirculation mode of operation. During cold leg injection and cold leg recirculation this penetration is not in service (valves closed) but is pressurized by the safety injection pumps to a pressure in excess of 1.1 times the containment design pressure. This ensures that leakage path for containment atmosphere does not exist during a LOCA. Therefore, these valves are not required to be Type C tested.
13. This penetration is an Engineered Safety Feature System supplying SI pump flow (valves opened) to the cold legs of the RCS during cold leg injection and cold leg recirculation modes of operation. During hot leg recirculation this penetration is not in service (valves closed) but is pressurized by the safety injection pumps to a pressure in excess of containment design pressure. This ensures that a leakage path for containment atmosphere does not exist during a LOCA. Therefore, these valves are not required to be Type C tested.
14. This penetration is an Engineered Safety Feature System supplying RHR pump flow (valves opened) to the hot legs of the RCS during hot leg recirculation mode of operation. During cold leg injection this penetration is not in service (valve closed) but is pressurized by the residual heat removal pumps to a pressure in excess of containment design pressure. During cold leg recirculation, this penetration is not in service but is isolated by a minimum of two additional valves outside containment. These valves are therefore not required to be Type C tested.
15. Due to the piping arrangement, these valves cannot be tested individually; as such the leak test will result in a combined leak rate for both isolation valves under test conditions.
16. These valves function as local manual isolation for penetrations MI-1, MI-4 following exhaustion of air accumulators for HV-2452-1, -2 (see FSAR Section 9.3.1.2 discussion regarding accumulators for main steam supply to AFW pump turbine).
17. These valves do not require Appendix J Type C leak rate testing. An effective fluid seal on these penetrations is provided by the suction sources to the residual heat removal pumps during and following an accident. In addition, these containment isolation valves are non-automatic, are not required to operate post-accident and are located inside containment. See Section 6.2.4.1.3, items 3 and 5 for details.

TABLE 6.2.4-3
CONTAINMENT ISOLATION VALVING APPLICATION (Note 1)

(Sheet 1 of 12)

Item	Containment Isolation Signal	Valve Position			Valve Power Failure	Valve Closure Time (Sec.)	Power Source	Remarks
		Normal	Shutdown	Post-Accident				
1	-	Opened	Opened/Closed	Closed	Closed (Note 2)	5	A/B	Closes on Steam Line Isolation Signal
2	-	Closed/opened	Closed	Closed	N/A	N/A	-	Main Steam Isolation Bypass Valve (Note 1)
3	-	Opened	Open/Closed	Closed	Closed	5	A/B	Closes on Steam Line Isolation Signal
4	-	Closed	Closed	Opened/Closed	Opened	N/A	B	(Note 5)
4a	-	Closed	Opened/Closed	Closed	N/A	N/A	-	TDAFW Pump Bypass Warm-up Valve
5	-	Closed	Closed	Opened/Closed	Closed	N/A	A	
5a	-	Closed	Closed	Closed	N/A	N/A	-	
5b	-	Closed	Closed	Closed	N/A	N/A	-	
6	-	Opened	Open/Closed	Closed	Closed(Note 2)	5	A/B	Closes on Steam Line Isolation Signal
7	-	Closed/Opened	Closed	Closed	N/A	N/A	-	Main Steam Isolation Bypass Valve (Note 1)
8	-	Opened	Opened/Closed	Closed	Closed	5	A/B	Closed on Steam Line Isolation Signal
9	-	Closed	Closed	Opened/Closed	Closed	N/A	B	
9a	-	Closed	Closed	Closed	N/A	N/A	-	
9b	-	Closed	Closed	Closed	N/A	N/A	-	
10	-	Opened	Opened/Closed	Closed	Closed(Note 2)	5	A/B	Closed on Steam Line Isolation Signal
11	-	Closed/Opened	Closed	Closed	N/A	N/A	-	Main Steam Isolation Bypass Valve (Note 1)
12		Opened	Open/Closed	Closed	Closed	5	A/B	Closed on Steam Line Isolation Signal
13	-	Closed	Closed	Opened/Closed	Closed	N/A	A	
13a	-	Closed	Closed	Closed	N/A	N/A	-	

TABLE 6.2.4-3
CONTAINMENT ISOLATION VALVING APPLICATION (Note 1)

(Sheet 2 of 12)

Item	Containment Isolation Signal	Valve Position Normal	Valve Position Shutdown	Valve Position Post-Accident	Valve Power Failure	Valve Closure Time (Sec.)	Power Source	Remarks
13b	-	Closed	Closed	Closed	N/A	N/A	-	
14	-	Opened	Open/Closed	Closed	Closed(Note 2)	5	A/B	Closed on Steam Line Isolation Signal
15		Closed/Opened	Closed	Closed	N/A	N/A	-	Main Steam Isolation Bypass Valve (Note 1)
16	-	Opened	Opened/Closed	Closed	Closed	5	A/B	Closed on Steam Line Isolation Signal
17	-	Closed	Closed	Opened/Closed	Opened	N/A	A	(Note 5)
17a	-	Closed	Opened/Closed	Closed	N/A	N/A	-	TDAFW Pump Bypass Warm-up Valve
18	-	Closed	Closed	Opened/Closed	Closed	N/A	B	
18a	-	Closed	Closed	Closed	N/A	N/A	-	
18b	-	Closed	Closed	Closed	N/A	N/A	-	
19	-	Opened	Closed	Closed	FAI	5	A/B	Closed on Feedwater Isolation Signal
20		Closed	Closed	Closed	Closed	N/A	B	Remote Manual Isolation satisfies CDC-57
20a	-	Opened	Opened	Opened/Closed	FAI	N/A	A	
-	Opened	Opened	Opened/Closed	FAI	N/A	B		
20b	-	Closed	Closed/Opened	Closed	N/A	N/A	-	
20c	-	Closed	Opened/Closed	Closed	Closed	5	A/B	Closes on Feedwater Isolation Signal (Unit 2 only, valve deleted Unit 1)
20d	-	Closed	Opened/Closed	Closed	Closed	5	A/B	Closed on Feedwater Isolation Signal
21	-	Opened	Closed	Closed	FAI	5	A/B	Closed on Feedwater Isolation Signal
22		Closed	Closed	Closed	Closed	N/A	B	Remote Manual Isolation satisfies CDC-57

TABLE 6.2.4-3
CONTAINMENT ISOLATION VALVING APPLICATION (Note 1)

(Sheet 3 of 12)

Item	Containment Isolation Signal	Valve Position			Valve Power Failure	Valve Closure Time (Sec.)	Power Source	Remarks
		Normal	Shutdown	Post-Accident				
22a	-	Opened	Opened	Opened/Closed	FAI	N/A	A	
-	Opened	Opened	Opened/Closed	FAI	N/A	B		
22b	-	Closed	Closed/Opened	Closed	N/A	N/A	-	
22c	-	Closed	Opened/Closed	Closed	Closed	5	A/B	Closed on Feedwater Isolation Signal (Unit 2 only, valve deleted Unit 1)
22d	-	Closed	Opened/Closed	Closed	Closed	5	A/B	Closed on Feedwater Isolation Signal
23	-	Opened	Closed	Closed	FAI	5	A/B	Closed on Feedwater Isolation Signal
24a	-	Opened	Opened	Opened/Closed	FAI	N/A	A	
-	Opened	Opened	Opened/Closed	FAI	N/A	B		
24b	-	Closed	Closed/Opened	Closed	N/A	N/A	-	
24c	-	Closed	Opened/Closed	Closed	Closed	5	A/B	Closed on Feedwater Isolation Signal (Unit 2 only, valve deleted Unit 1)
24d	-	Closed	Opened/Closed	Closed	Closed	5	A/B	Closed on Feedwater Isolation Signal
25	-	Opened	Closed	Closed	FAI	5	A/B	Closed on Feedwater Isolation Signal
26a	-	Opened	Opened	Opened/Closed	FAI	N/A	A	
-	Opened	Opened	Opened/Closed	FAI	N/A	B		
26b	-	Closed	Closed/Opened	Closed	N/A	N/A	-	
26c	-	Closed	Opened/Closed	Closed	Closed	5	A/B	Closed on Feedwater Isolation Signal (Unit 2 only, valve deleted Unit 1)
26d	-	Closed	Opened/Closed	Closed	Closed	5	A/B	Closed on Feedwater Isolation Signal
27	Phase A	Opened	Closed	Closed	Closed	5	A/B	Remote Manual Isolation Satisfies CDC-57

TABLE 6.2.4-3
CONTAINMENT ISOLATION VALVING APPLICATION (Note 1)

(Sheet 4 of 12)

Item	Containment Isolation Signal	Valve Position Normal	Valve Position Shutdown	Valve Position Post-Accident	Valve Power Failure	Valve Closure Time (Sec.)	Power Source	Remarks
28	Phase A	Opened	Closed	Closed	Closed	5	A/B	Remote Manual Isolation Satisfies CDC-57
29	Phase A	Opened	Closed	Closed	Closed	5	A/B	Remote Manual Isolation Satisfies CDC-57
30	Phase A	Opened	Closed	Closed	Closed	5	A/B	Remote Manual Isolation Satisfies CDC-57
31	-	-	-	-	-	-	-	
32	Phase A	Opened	Closed	Closed	Closed	10	B	
	Phase A	Opened	Closed	Closed	Closed	10	A	
33	-	Closed/Opened	Opened	Closed	FAI	N/A	B	Relief valve is
		Closed	Closed	Closed	N/A	N/A	-	closed in backflow direction at all times
34	-	Closed/Opened	Opened	Closed	FAI	N/A	A	Relief valve is
		Closed	Closed	Closed	N/A	N/A	-	closed in backflow direction at all times
35	-	Opened	Opened	Opened/Closed	FAI	N/A	A	
	-	Closed	Closed	Opened/Closed	-	-	-	Check Valve
	Phase A	Closed	Closed	Closed	Closed	15	A	Air operated valve on test line
36	-	Opened	Opened	Opened	FAI	-	B	
	Closed	Closed	Opened/Closed	-	-	-		Check Valve
	Phase A	Closed	Closed	Closed	Closed	15	B	Air operated valve on test line
37	-	-	-	-	-	-	-	
38	-	-	-	-	-	-	-	
39	-	-	-	-	-	-	-	
40(a)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Flanged
40(b)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Flanged
40(c)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Flanged
41	-	Closed	Closed	Closed	-	-	-	Check Valve
	Phase A	Closed	Closed	Closed	Closed	10	B	
41a	-	Closed	Closed	Open/Closed	N/A	N/A	-	Thermal Relief Valve

TABLE 6.2.4-3
CONTAINMENT ISOLATION VALVING APPLICATION (Note 1)

(Sheet 5 of 12)

Item	Containment Isolation Signal	Valve Position Normal	Shutdown	Post-Accident	Valve Power Failure	Valve Closure Time (Sec.)	Power Source	Remarks
42	-	Closed	Closed	Open	-	-	-	Check Valve
	-	Closed	Closed	Opened	FAI	N/A	A	
	-	Closed	Closed	Opened	FAI	N/A	B	
	Phase A	Closed	Closed	Closed	Closed	10	B	Air operated valve on test line
43	-	Closed	Closed	Closed/Opened	FAI	N/A	A	
	-	Closed	Closed	Closed/Opened	-	-	-	Check Valve
	Phase A	Closed	Closed	Closed	Closed	10	A	Air operated valve on test line
44	-	Closed	Closed	Closed/Opened	FAI	N/A	B	
	-	Closed	Closed	Closed/Opened	-	-	-	Check Valve
	Phase A	Closed	Closed	Closed	Closed	10	A	Air operated valve on test line
45	-	Opened	Opened	Opened	FAI	N/A	B	
	-	Closed	Closed	Opened/Closed	-	-	-	Check Valve
	-	Closed	Closed	Opened/Closed	-	-	-	Check Valve
	-	Closed	Closed	Opened/Closed	-	-	-	Check Valve
	-	Closed	Closed	Opened/Closed	-	-	-	Check Valve
	Phase A	Closed	Closed	Closed	Closed	10	A	Air operated valve on test line
46	-	Opened	Closed	Closed	FAI	10	B	Closed on Safety Injection
		Opened	Closed	Closed	-	-	-	Check Valve
47	-	Opened	Opened/Closed	Opened	-	-	-	Check Valve
	-	Opened	Opened/Closed	Open	FAI	N/A	B	
48	-	Opened	Open/Closed	Open	-	-	-	Check Valve
	-	Opened	Opened/Closed	Open	FAI	N/A	B	

TABLE 6.2.4-3
CONTAINMENT ISOLATION VALVING APPLICATION (Note 1)

(Sheet 6 of 12)

Item	Containment Isolation Signal	Valve Position Normal	Shutdown	Post-Accident	Valve Power Failure	Valve Closure Time (Sec.)	Power Source	Remarks
49	-	Opened	Opened/Closed	Opened	-	-	-	Check Valve
	-	Opened	Opened/Closed	Open	FAI	N/A	B	
50	-	Opened	Opened/Closed	Opened	-	-	-	Check Valve
	-	Opened	Opened/Closed	Open	FAI	N/A	B	
51	Phase A	Opened	Opened/Closed	Closed	FAI	10	B (8100)	
	Phase A	Opened	Opened/Closed	Closed	FAI	10	A (8112)	
	-	Closed	Closed	Open/Closed	-	-	-	Thermal Relief Check Valve
52	Phase A	Opened	Opened	Closed	Closed	10	B	
	Phase A	Opened	Opened	Closed	Closed	10	A	
	-	Closed	Closed	Closed	N/A	N/A	-	Manual Valve
52a	-	Closed	Closed	Open/Closed	N/A	N/A	-	Thermal Relief Valve
53	-	-	-	-	-	-	-	
54	-	Closed	Closed	Closed/Opened	FAI	N/A	B	
	-	Closed	Closed	Closed/Open	-	-	-	Check Valve
55	-	Closed	Closed	Closed/Opened	FAI	-	A	
	-	Closed	Closed	Closed/Open	-	-	-	Check Valve
56	-	Closed	Closed	Closed	N/A	N/A	-	
	-	Closed	Opened/Closed	Closed	N/A	N/A	-	
57	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
58	Containment Vent. Isolation	Closed	Closed	Closed/Open	FAI	N/A	B (HV-5542)	(Note 3)
	Containment Vent. Isolation	Closed	Closed	Closed/Open	FAI	N/A	A (HV-5543)	(Note 3)
	Containment Vent. Isolation	Closed	Closed	Closed/Open	FAI	N/A	B (HV-5563)	(Note 3)

TABLE 6.2.4-3
CONTAINMENT ISOLATION VALVING APPLICATION (Note 1)

(Sheet 7 of 12)

Item	Containment Isolation Signal	Valve Position Normal	Shutdown	Post-Accident	Valve Power Failure	Valve Closure Time (Sec.)	Power Source	Remarks
59	Containment Vent. Isolation	Closed	Closed	Closed/Open	FAI	N/A	B (HV-5540)	(Note 3)
	Containment Vent. Isolation	Closed	Closed	Closed/Open	FAI	N/A	A (HV-5541)	(Note 3)
	Containment Vent. Isolation	Closed	Closed	Closed/Open	FAI	N/A	B (HV-5562)	(Note 3)
60	Phase A	Closed	Opened	Closed	Closed	5	B	Provides automatic fire protection water
	Phase A	Closed	Opened	Closed	Closed	5	A	
60a	-	Closed	Closed	Open/Closed	N/A	N/A	-	Thermal Relief Valve
61	Phase A	Open	Closed	Closed	Closed	5	B	
	Phase A	Open	Closed	Closed	Closed	5	A	
61a	-	Closed	Closed	Open/Closed	N/A	N/A	-	Thermal Relief Valve
62	Phase A	Open	Open	Closed/Open	Closed	5	B	
	-	Open	Open	Closed/Open	-		-	Check Valve
63	-	Closed	Closed	Closed/Opened	FAI	A/N	B	
	Phase A	Closed	Closed	Closed	Closed	15	A	Air operated valve on test line
	-	Closed	Closed	Closed/Opened	-	-	-	Check Valve
	-	Closed	Closed	Closed/Opened	-	-	-	Check Valve
64	-	-	-	-	-	-	-	
65	-	-	-	-	-	-	-	
66	-	-	-	-	-	-	-	
67	-	Closed	Closed	Closed	N/A	N/A	-	
	-	Closed	Closed	Closed	N/A	N/A	-	
68	-	-	-	-	-	-	-	
69	-	-	-	-	-	-	-	
70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
71	-	Closed	Closed	Closed	N/A	N/A	-	
	-	Closed	Closed	Closed	N/A	N/A	-	

TABLE 6.2.4-3
CONTAINMENT ISOLATION VALVING APPLICATION (Note 1)

(Sheet 8 of 12)

Item	Containment Isolation Signal	Valve Position			Valve Power Failure	Valve Closure Time (Sec.)	Power Source	Remarks
		Normal	Shutdown	Post-Accident				
72	-	-	-	-	-	-	-	
73	Phase A	Opened	Closed	Closed	Closed	5	B	Remote Manual Isolation Satisfies CDC-57
74	Phase A	Closed	Closed	Closed/Open	Closed	5	B	
	Phase A	Closed	Closed	Closed/Open	Closed	5	A	
	Phase A	Closed	Closed	Closed/Open	Closed	5	A	
74a	-	Closed	Closed	Open/Closed	N/A	N/A	-	Thermal Relief Valve
75	-	-	-	-	-	-		
76	Phase A	Opened	Closed	Closed	Closed	5	B	Remote Manual Isolation Satisfies CDC-57
77	Phase A	Closed	Closed	Closed	Closed	5	B	
	Phase A	Closed	Closed	Closed	Closed	5	A	
77a	-	Closed	Closed	Open/Closed	N/A	N/A	-	Thermal Relief Valve
78	Phase A	Closed	Closed	Closed	Closed	5	B	
	Phase A	Closed	Closed	Closed	Closed	5	A	
78a	-	Closed	Closed	Open/Closed	N/A	N/A	-	Thermal Relief Valve
79	Phase A	Opened	Closed	Closed	Closed	5	B	Remote Manual Isolation Satisfies CDC-57
80	Phase A	Closed	Closed	Closed	Closed	5	B	
	Phase A	Closed	Closed	Closed	Closed	5	A	
	Phase A	Closed	Closed	Closed	Closed	5	A	
	Phase A	Closed	Closed	Closed	Closed	5	A	
	Phase A	Closed	Closed	Closed	Closed	5	A	
80a	-	Closed	Closed	Open/Closed	N/A	N/A	-	Thermal Relief Valve
81	Phase A	Closed	Closed	Closed	Closed	5	B	
	Phase A	Closed	Closed	Closed	Closed	5	A	
81a	-	Closed	Closed	Open/Closed	N/A	N/A	-	Thermal Relief Valve
82	Phase A	Opened	Closed	Closed	Closed	5	B	Remote Manual Satisfies Isolation CDC-57

TABLE 6.2.4-3
CONTAINMENT ISOLATION VALVING APPLICATION (Note 1)

(Sheet 9 of 12)

Item	Containment Isolation Signal	Valve Position			Valve Power Failure	Valve Closure Time (Sec.)	Power Source	Remarks
		Normal	Shutdown	Post-Accident				
83	Phase A	Closed	Closed	Closed	Closed	10	A	
	Phase A	Closed	Closed	Closed	Closed	10	B	
	Phase A	Closed	Closed	Closed	Closed	10	B	
83a	-	Closed	Closed	Open/Closed	N/A	N/A	-	Thermal Relief Valve
84	Phase A	Closed	Closed	Closed	Closed	5	A	
	Phase A	Closed	Closed	Closed	Closed	5	B	
85	-	-	-	-	-	-	-	
86	-	-	-	-	-	-	-	
87	-	-	-	-	-	-	-	
88	-	-	-	-	-	-	-	
89	-	-	-	-	-	-	-	
90	-	-	-	-	-	-	-	
91	-	-	-	-	-	-	-	
92	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Bellows Seal
93	-	-	-	-	-	-	-	
94	Phase A	Opened	Opened	Closed	Closed	5	B	
	Phase A	Opened	Opened	Closed	Closed	5	A	
95	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Bellows Seal
96	-	-	-	-	-	-	-	
97	Phase A	Closed	Closed	Closed	Closed	5	A	
	Phase A	Closed	Closed	Closed	Closed	5	B	
98	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Bellows Seal
99	-	-	-	-	-	-	-	
100	Phase A	Closed	Closed	Closed	Closed	5	A	
	Phase A	Closed	Closed	Closed	Closed	5	B	
101	-	N/A	N/A	N/A	N/A	-	-	
102	Phase A	Opened	Opened	Closed	Closed	5	B	
	Phase A	Opened	Opened	Closed	Closed	5	A	
103	-	-	-	-	-	-	-	

TABLE 6.2.4-3
CONTAINMENT ISOLATION VALVING APPLICATION (Note 1)

(Sheet 10 of 12)

Item	Containment Isolation Signal	Valve Position			Valve Power Failure	Valve Closure Time (Sec.)	Power Source	Remarks
		Normal	Shutdown	Post-Accident				
104	Phase A	Opened	Opened	Closed	Closed	10	B	
	-	Opened	Opened	Closed	-	-	-	Check Valve
105	Phase A	Closed	Closed	Closed	Closed	10	A	
	Phase A	Closed	Closed	Closed	Closed	10	B	
106	-	-	-	-	-	-	-	
107	-	-	-	-	-	-	-	
108	-	-	-	-	-	-	-	
109	Containment Vent Isolation	Closed	Opened	Closed	Closed	N/A	B	(Note 3)
	Containment Vent Isolation	Closed	Opened	Closed	Closed	N/A	A	(Note 3)
110	Containment Vent Isolation	Closed	Opened	Closed	Closed	N/A	B	(Note 3)
	Containment Vent Isolation	Closed	Opened	Closed	Closed	N/A	A	(Note 3)
111	Phase A	Opened	Opened/Closed	Closed	Closed	5	B	Remote Manual Isolation Satisfies CDC-57
112	Phase A	Opened	Opened/Closed	Closed	Closed	5	B	Remote Manual Isolation Satisfies CDC-57
113	-	Closed	Opened	Closed	-	-	-	Check Valve
	Phase A	Closed	Opened	Closed	Closed	5	B	
114	Phase A	Opened	Opened	Closed	Closed	10	A	
	Phase A	Opened	Opened	Closed	Closed	10	B	
114a	-	Closed	Closed	Open/Closed	N/A	N/A	-	Thermal Relief Valve
115	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Flanged
116	Phase A	Closed	Closed	Closed	Closed	10	B	
	Phase A	Closed	Closed	Closed	Closed	10	A	
117	Phase B	Opened	Opened	Closed	FAI	30	B (HV-4708)	
	Phase B	Opened	Opened	Closed	FAI	30	A (HV-4701)	
	-	Closed	Closed	Closed/Opened	-	-	-	Thermal Relief Check Valve

TABLE 6.2.4-3
CONTAINMENT ISOLATION VALVING APPLICATION (Note 1)

(Sheet 11 of 12)

Item	Containment Isolation Signal	Valve Position Normal	Shutdown	Post-Accident	Valve Power Failure	Valve Closure Time (Sec.)	Power Source	Remarks
118	Phase B	Opened	Opened/	Closed	FAI	30	B	
	-	Opened	Opened	Closed	-	-	-	Check Valve
119	Phase B	Opened	Opened	Closed	FAI	15	B (HV-4709)	
	Phase B	Opened	Opened	Closed	FAI	15	A	
	-	Closed	Closed	Closed/Open	-	-	-	Thermal Relief Check Valve
120	Phase A	Opened	Opened	Closed	FAI	15	B	
	-	Opened	Opened	Closed	-	-	-	Check Valve
120a	-	Closed	Closed	Open/Closed	N/A	N/A	-	Thermal Relief Valve
121	Phase A	Opened	Opened	Closed	FAI	15	B (HV-6082)	
	Phase A	Opened	Opened	Closed	FAI	15	A (HV-6083)	
121a	-	Closed	Closed	Open/Closed	N/A	N/A	-	Thermal Relief Valve
122	Containment Vent Isolation	Closed/Opened	Closed	Closed	Closed	3 (Note 4)	B	Intermittently opened in normal
	Containment Vent Isolation	Closed/Opened	Closed	Closed	Closed	3 (Note 4)	A	operation to function as part of the containment pressure relief system.
123	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Flanged
124	Phase A	Closed	Closed	Closed	FAI	10	B(4075B)	
	Phase A	Closed	Closed	Closed	FAI	10	A(4075C)	
125	-	Closed	Closed	Closed/Opened	FAI	N/A	A	
	-	Closed	Closed	Closed	N/A	N/A	-	Thermal Relief
126	-	Closed	Closed	Closed/Opened	FAI	N/A	B	
	-	Closed	Closed	Closed	N/A	N/A	-	Thermal Relief
127	-	Closed	Closed	Closed/Opened	FAI	N/A	A	
	-	Closed	Closed	Closed	N/A	N/A	-	Thermal Relief
128	-	Closed	Closed	Closed/Opened	FAI	N/A	B	
	-	Closed	Closed	Closed	N/A	N/A	-	Thermal Relief
129	N/A	N/A	N/A	N/A	N/A	N/A	-	

TABLE 6.2.4-3
CONTAINMENT ISOLATION VALVING APPLICATION (Note 1)

(Sheet 12 of 12)

Item	Containment Isolation Signal	Valve Position Normal	Shutdown	Post-Accident	Valve Power Failure	Valve Closure Time (Sec.)	Power Source	Remarks
130	-	Closed	N/A	Closed	N/A	N/A	N/A	
	-	Closed	N/A	Closed	N/A	N/A	N/A	
131	-	Closed	N/A	Closed	FAI	N/A	N/A	
	-	Closed	N/A	Closed	FAI	N/A	N/A	
131a	-	Closed	N/A	Closed	N/A	N/A	N/A	
	-	Closed	N/A	Closed	N/A	N/A	N/A	
	-	Closed	N/A	Closed	N/A	N/A	N/A	
	-	Closed	N/A	Closed	N/A	N/A	N/A	
132	-	Closed	N/A	Closed	N/A	N/A	N/A	
	-	Closed	N/A	Closed	N/A	N/A	N/A	
133	-	Closed	N/A	Closed	N/A	N/A	N/A	
	-	Closed	N/A	Closed	N/A	N/A	N/A	
	-	Closed	N/A	Closed	N/A	N/A	N/A	
	-	Closed	N/A	Closed	N/A	N/A	N/A	
134	-	Closed	N/A	Closed	FAI	N/A	N/A	
	-	Closed	N/A	Closed	FAI	N/A	N/A	
134a	-	Closed	N/A	Closed	N/A	N/A	N/A	
	-	Closed	N/A	Closed	N/A	N/A	N/A	
	-	Closed	N/A	Closed	N/A	N/A	N/A	
	-	Closed	N/A	Closed	N/A	N/A	N/A	

Notes:

1 - MSIV Bypass valves are locked closed except during startup when one may be opened to warm up main steam piping.

2 - Valve fails closed on loss of hydraulic pressure. Either pilot solenoid must be energized to cause valve close when hydraulic pressure is available.

3 - Sealed closed in Modes 1-4.

4 - Technical Requirements Table 2.1.1, “Containment Isolation Valves,” requires a maximum isolation time of 5 seconds for valves HV-5548 and HV-5549 with a footnote stating that the 5 second time includes the instrumentation delays of the containment ventilation isolation signal from Pressurizer Pressure Low.”

5 - Manual isolation valves upstream of TDAFWP steam supply valves are normally open. Closed for steam line isolation concurrent with loss of air to the Steam Supply Valve

TABLE 6.2.4-4
PENETRATIONS THAT ARE NOT DRAINED AND VENTED DURING
CONTAINMENT INTEGRATED LEAKAGE RATE (TYPE A) TEST**

Item	Penetration No.	System
33	MII-2	RHR
34	MII-3	RHR
35	MII-4	SI
36	MII-5	SI
42	MIII-2	SI
43	MIII-3	SI
44	MIII-4	SI
45	MIII-5	SI
47*	MIII-7	CS
48*	MIII-8	CS
49*	MIII-9	CS
50*	MIII-10	CS
54	MIII-14	CT
55	MIII-15	CT
63	MIII-23	SI
92	MIV-7 (b)	VA
95	MIV-8 (b)	VA
98	MIV-9 (b)	VA
101	MIV-10 (b)	VA
120*	MV-12	CH
120a*	MV-13	CH
121*	MV-13	CH
121a	MV-13	CH
125	MS-1	SI
126	MS-2	SI
127	MS-3	CT
128	MS-4	CT

* Items may be water filled during Type A testing but are not necessarily water filled post-accident.

** Type C penetrations, conforming to GDC-57, are not necessarily drained or vented during the Type A test. See Table 6.2.4-1, Items 1 to 30, 73, 76, 79, 82, 111, 112, 130

In addition other penetrations not shown on this table may not be vented and drained as discussed in Section 6.2.6.1.

TABLE 6.2.4-5
TABLE 6.2.4-5 HAS BEEN DELETED.

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 1 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
1	MI-1	MS	Main Steam From Steam Generator #1	non-essential	none
2	MI-1	MS	MSIV Bypass From Steam Generator #1	non-essential	none
3	MI-1	MS	Drain From Main Steamline #1	non-essential	none
4	MI-1	MS	None	essential	Main Steam to Aux. F.P. Turbine From Steamline #1
4a	MI-1	MS	None	non-essential	none
5	MI-1	MS	Main Steam From Steam Generator #1	essential	Atmospheric Relief
5a	MI-1	MS	N_2 Supply to Steam Generator #1	non-essential	none
5b	MI-1	MS	Main Steam From Steam Generator #1	essential	Main Steam Pressure Relief
6	MI-2	MS	Main Steam From Steam Generator #2	non-essential	none
7	MI-2	MS	MSIV Bypass From Steam Generator #2	non-essential	none
8	MI-2	MS	Drain From Steam Line #2	non-essential	none
9	MI-2	MS	Main Steam From Steam Generator #2	essential	Atmospheric Relief
9a	MI-2	MS	N_2 Supply to Steam Generator #2	non-essential	none

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 2 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
9b	MI-2	MS	Main Steam From Steam Generator #2	essential	Main Steam Pressure Relief
10	MI-3	MS	Main Steam From Steam Generator #3	non-essential	none
11	MI-3	MS	MSIV Bypass From Steam Generator #3	non-essential	none
12	MI-3	MS	Drain From Steam Line #3	non-essential	none
13	MI-3	MS	Main Steam From Steam Generator #3	essential	Atmospheric Relief
13a	MI-3	MS	N_2 Supply to Steam Generator #3	non-essential	none
13b	MI-3	MS	Main Steam from Steam Generator #3	essential	Atmospheric Relief
14	MI-4	MS	Main Steam From Steam Generator #4	non-essential	none
15	MI-4	MS	MSIV Bypass From Steam Generator #4	non-essential	none
16	MI-4	MS	Drain From Steam Line #4	non-essential	none
17	MI-4	MS	None	essential	Main Steam to Aux. F.P. Turbine from Steam Line #4
17a	MI-4	MS	None	non-essential	none
18	MI-4	MS	Main Steam From Steam Generator #4	essential	Atmospheric Relief
18a	MI-4	MS	N_2 Supply to Steam Generator #4	non-essential	none

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 3 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
18b	MI-4	MS	Main Steam From Steam Generator #4	essential	Main Steam Pressure Relief
19	MI-5	FW	Feedwater to Steam Generator #1	non-essential	none
20	MI-5	FW	Feedwater Sample (FW to Steam Generator #1)	non-essential	none
20a	MV-18	FW/AFW	Auxiliary Feedwater to Steam Generator #1	essential	Auxiliary Feedwater to Steam Generator
20b	MI-5	FW	N_2 Supply to Steam Generator #1	non-essential	none
20c	MV-18	FW	Feedwater Preheater Bypass to Steam Generator #1 (Unit 2 only)	non-essential	none
20d	MI-5	FW	Feedwater Bypass to Steam Generator #1	non-essential	none
21	MI-6	FW	Feedwater to Steam Generator #2	non-essential	none
22	MI-6	FW	Secondary Sample (FW to Steam Generator #2)	non-essential	none
22a	MV-19	FW/AFW	Auxiliary Feedwater to Steam Generator #2	essential	Auxiliary Feedwater to Steam Generator
22b	MI-6	FW	N_2 Supply to Steam Generator #2	non-essential	none
22c	MV-19	FW	Feedwater Preheater Bypass to Steam Generator #2 (Unit 2 only)	non-essential	none

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 4 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
22d	MI-6	FW	Feedwater Bypass to Steam Generator #2	non-essential	none
23	MI-7	FW	Feedwater to Steam Generator #3	non-essential	none
24a	MV-20	FW/AFW	Auxiliary Feedwater to Steam Generator #3	essential	Auxiliary Feedwater to Steam Generator
24b	MI-7	FW	N_2 Supply to Steam Generator #3	non-essential	none
24c	MV-20	FW	Feedwater Preheater Bypass to Steam Generator #3 (Unit 2 only)	non-essential	none
24d	MI-7	FW	Feedwater Bypass to Steam Generator #3	non-essential	none
25	MI-8	FW	Feedwater to Steam Generator #4	non-essential	none
26a	MV-17	FW/AFW	Auxiliary Feedwater to Steam Generator #4	essential	Auxiliary Feedwater to Steam Generator
26b	MI-8	FW	N_2 Supply to Steam Generator #4	non-essential	none
26c	MV-17	FW	Feedwater Preheater Bypass to Steam Generator #4 (Unit 2 only)	non-essential	none
26d	MI-8	FW	Feedwater Bypass to Steam Generator #4	non-essential	none
27	MI-9	MS	Blowdown From Steam Generator #3	non-essential	none

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 5 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
28	MI-10	MS	Blowdown From Steam Generator #2	non-essential	none
29	MI-11	MS	Blowdown From Steam Generator #1	non-essential	none
30	MI-12	MS	Blowdown From Steam Generator #4	non-essential	none
31	MI-13	-	Spare	-	-
32	MII-1	CS	Letdown Line to Letdown Heat Exchanger	non-essential	none
33	MII-2	RH	R.H.R. From Hot Leg Loop #4	non-essential	none
34	MII-3	RH	R.H.R. From Hot Leg Loop #1	non-essential	none
35	MII-4	SI	None	essential	Injection of cooling water into the cold leg loops #1 and #2
36	MII-5	SI	None	essential	Injection of cooling water into the cold leg loops #3 and #4
37	MII-6	-	Spare	-	-
38	MII-7	-	Spare	-	-
39	MII-8	-	Spare	-	-
40a	MII-9A	-	Maintenance Penetration	non-essential	none

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 6 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
40b	MII-9B	-	Maintenance Penetration	non-essential	none
40c	MII-9C	-	Maintenance Penetration	non-essential	none
41	MIII-1	RC	Reactor Make Up Water To Pressure Relief Tank & R.C. Pump Stand Pipe	non-essential	none
41a	MIII-1	RC	None	non-essential	none
42	MIII-2	SI	None	essential	Safety Injection to Cold Leg Loops #1, #2, #3, & #4
43	MIII-3	SI	None	essential	S.I. To R.C. System Hot Leg Loops #2 & #3
44	MIII-4	SI	None	essential	S.I. To R.C. System Hot Leg Loops #1 & #4
45	MIII-5	SI	None	essential	S.I. To R.C. System Cold Leg Loops #1, #2, #3, & #4
46	MIII-6	CS	Charging Line Regenerative Heat Exchanger	non-essential	none
47	MIII-7	CS	Seal Injection to R.C. Pump (Loop #1)	Essential (Note 2)	Seal Water Injection

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 7 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
48	MIII-8	CS	Seal Injection to R.C. Pump (Loop #2)	Essential (Note 2)	Seal Water Injection
49	MIII-9	CS	Seal Injection to R.C. Pump (Loop #3)	Essential (Note 2)	Seal Water Injection
50	MIII-10	CS	Seal Injection to R.C. Pump (Loop #4)	Essential (Note 2)	Seal Water Injection
51	MIII-11	CS	Seal Water Return to R.C. Excess Letdown	non-essential	none
52	MIII-12	WP	R.C.D.T. Heat Exchanger To Waste Hold Up Tank	non-essential	
52a	MIII-12	WP	None	non-essential	none
53	MIII-13	-	Spare	-	-
54	MIII-14	CT	None	essential	Containment Spray To Spray Header (Train B)
55	MIII-15	CT	None	essential	Containment Spray To Spray Header (Train A)
56	MIII-16	SF	Refueling Water Purification to Refueling Cavity	non-essential	none
57	MIII-17	LT	None	non-essential	none

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 8 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
58	MIII-18	VA	None	non-essential	none
59	MIII-19	VA	None	non-essential	none
60	MIII-20	DD	Demineralized Water Supply	non-essential	none
60a	MIII-20	DD	None	non-essential	none
61	MIII-21	VD	Containment Sump Pump Discharge	non-essential	none
61a	MIII-21	VD	None	non-essential	none
62	MIII-22	CI	Instrument Air to Containment	non-essential	Post-Accident Sampling
63	MIII-23 #2 & #3	SI	R.H.R. To Hot Leg Loops	essential	Core Cooling
64	MIII-24	-	Spare	-	-
65	MIII-25	-	Spare	-	-
66	MIII-26	-	Spare	-	-
67	MIII-27	SF	Refueling Cavity to Refueling Water Purification Pump	non-essential	none
68	MIII-28	-	Spare	-	-

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 9 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
69	MIII-29	-	Spare	-	-
70	MIII-30	LT	none	non-essential	none
71	MIII-31	SF	Refueling Cavity Skimmer Pump Discharge (System no longer used)	non-essential	none
72	MIII-32	-	Spare	-	-
73	MIV-1(a)	MS	Sample From Steam Generator #1	non-essential	none
74	MIV-1(b)	PS	R.C. Sample From Hot Legs	non-essential	Reactor Coolant Sampling
74a	MIV-1(b)	PS	None	non-essential	None
75	MIV-1(c)	-	Spare	-	-
76	MIV-2(a)	MS	Sample From Steam Generator #2	non-essential	None
77	MIV-2(b)	PS	Pressurizer Liquid Space Sample	non-essential	None
77a	MIV-2(b)	PS	None	non-essential	None
78	MIV-2(c)	PS	Pressurizer Steam Space Sample	non-essential	None
78a	MIV-2(c)	PS	None	non-essential	None
79	MIV-3(a)	MS	Sample From Steam Generator #3	non-essential	None

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 10 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
80	MIV-3(b)	PS	Sample From Accumulators	non-essential	None
80a	MIV-3(b)	PS	None	non-essential	None
81	MIV-3(c)	WP	None	non-essential	None
81a	MIV-3(c)	WP	None	non-essential	None
82	MIV-4(a)	MS	Sample From Steam Generator #4	non-essential	None
83	MIV-4(b)	SI	Accumulator Test & Fill	non-essential	None
83a	MIV-4(b)	SI	None	non-essential	None
84	MIV-4(c)	PS	None	non-essential	None
85	MIV-5(a)	-	Spare	-	-
86	MIV-5(b)	-	Spare	-	-
87	MIV-5(c)	-	Spare	-	-
88	MIV-6(a)	-	Spare	-	-
89	MIV-6(b)	-	Spare	-	-
90	MIV-6(c)	-	Spare	-	-

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 11 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
91	MIV-7(a)	-	Spare	-	-
92	MIV-7(b)	ESFAS	Containment Pressure Sensing PT-934	essential measurement	Containment pressure
93	MIV-7(c)	-	Spare	-	-
94	MIV-8(a)	RM	Radiation Monitoring Sample	non-essential	None
95	MIV-8(b)	ESFAS	Containment Pressure Sensing PT-935	essential measurement	Containment pressure
96	MIV-8(c)	-	Spare	-	-
97	MIV-9(a)	PS	None	non-essential	None
98	MIV-9(b)	ESFAS	Containment Pressure Sensing PT-936	essential measurement	Containment Pressure
99	MIV-9(c)	-	Spare	-	-
100	MIV-10(a)	PS	None	non-essential	None
101	MIV-10(b)	ESFAS	Containment Pressure Sensing PT-937	essential measurement	Containment Pressure
102	MIV-10(c)	RM	Radiation Monitoring Sample return	non-essential	None

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 12 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
103	MIV-11(a)	-	Spare	-	-
104	MIV-11(b)	SI	N^2 Supply To Accumulators	non-essential	None
105	MIV-11(c)	WP	H^2 Supply to RC Drain Tank	non-essential	None
106	MIV-12(a)	-	Spare	-	-
107	MIV-12(b)	-	Spare	-	-
108	MIV-12(c)	-	Spare	-	-
109	MV-1	VA	Containment Purge Air Supply	non-essential	none
110	MV-2	VA	Containment Purge Air Exhaust	non-essential	none
111	MV-3	CC	C.C.W. Supply to Excess Letdown & RC Drain Tank Heat Exchanger	non-essential	none
112	MV-4	CC	C.C.W. Return from Excess Letdown & RC Drain Tank Heat Exchanger	non-essential	none
113	MV-5	CA	Service Air to Containment	non-essential	none
114	MV-6	CC	Containment CCW Drain Tank Pumps Discharge	non-essential	none

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 13 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
114a	MV-6	CC	None	non-essential	none
115	MV-7	LT	Containment Leak Rate Test Pressure Sensing	non-essential	none
116	MV-8	RC	N_2 Supply to Pressurizer Relief Tank	non-essential	none
117	MV-9	CC	CCW Return From RCP Motors	essential (Note 1)	Cooling of RCP motors
118	MV-10	CC	CCW Supply to RCP Motors and Thermal Barrier	essential (Note 1)	Cooling of RCP motors and Thermal Barriers
119	MV-11	CC	CCW Return From RCP Thermal Barrier	essential (Note 1)	Cooling of RCP Thermal Barrier
120	MV-12	CH	Chilled Water Supply To Containment Coolers	non-essential	none
120a	MV-12	CH	None	non-essential	none
121	MV-13	CH	Chilled Water Return From Containment Coolers	non-essential	none
121a	MV-13	CH	None	non-essential	none
122	MV-14	VA	Containment Pressure Relief	non-essential	none
123	MV-15	-	Maintenance Penetration	non-essential	none
124	MV-16	FP	Fire Protection System Isolation	non-essential	none

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 14 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
125	MS-1	SI	None	essential	Containment Recirculation Sump To R.H.R. Pump (Train A)
126	MS-2	SI	None	essential	Containment Recirculation Sump To R.H.R. Pump (Train B)
127	MS-3	CT	None	essential	Containment Recirculation Sump To Spray Pumps (Train A)
128	MS-4	CT	None	essential	Containment Recirculation Sump To Spray Pumps (Train B)
129	MS-5	-	Fuel Transfer Tube	non-essential	none
130	Unit 1 Personnel Airlock Hydraulics	BS/CB	Door Operating Mechanism	Non-essential	None
131	Unit 1 Personnel Airlock	BS/CB	Equalization of Door Differential Pressure	Non-essential	None
131a	Unit 1 Personnel Airlock	BS/CB	Equalization of Door Differential Pressure	Non-essential	None

TABLE 6.2.4-6
CLASSIFICATION OF SYSTEMS PATHS PENETRATION CONTAINMENT WALL

(Sheet 15 of 15)

Item	Penetration Number	System	Normal Operating Function	Classification	Post-Accident Function
132	Emergency Airlock	BS/CB	Equalization of Door Differential Pressure	Non-essential	None
133	Unit 2 Personnel Airlock Hydraulics	BS/CB	Door Operating Mechanism	Non-essential	None
134	Unit 2 Personnel Airlock	BS/CB	Equalization of Door Differential Pressure	Non-essential	None
134a	Unit 2 Personnel Airlock	BS/CB	Equalization of Door Differential Pressure	Non-essential	None

Notes:

1 - Essential for those accident conditions where the "P" has not been generated. The system is classified as non-essential after "P" signal actuation.

2 - See FSAR Section 6.2.4.1.4 paragraph 4.

TABLE 6.2.5-1
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TABLE 6.2.5-2
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TABLE 6.2.5-3
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TABLE 6.2.5-4
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TABLE 6.2.5-5
FAILURE MODE AND EFFECTS ANALYSIS

Component of System	Malfunction	Comments and Consequences
Containment Spray System	Fails to operate and provide mixing of containment atmosphere	Two redundant containment spray trains are provided. Operation of one train is adequate for mixing of hydrogen in the post- LOCA containment atmosphere.

TABLE 6.2.5-6
HYDROGEN PURGE SYSTEM COMPONENT MATERIALS SPECIFICATION

COMPONENT	MATERIAL
Exhaust Housing	A36CS
Prefilters	Fiberglass
HEPA Filters	Fiberglass
Charcoal Adsorbers	Perforated Stainless Steel

TABLE 6.2.5A-1
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6.3 EMERGENCY CORE COOLING SYSTEM

6.3.1 DESIGN BASES

The Emergency Core Cooling System (ECCS) is designed to cool the reactor core and provide shutdown capability following initiation of the following accident conditions:

1. Pipe breaks in the Reactor Coolant System (RCS) which cause a discharge larger than that which can be made up by the normal makeup system, up to and including the instantaneous circumferential rupture of the largest pipe in the RCS.

2. Rod cluster control assembly ejection accident.

3. Pipe breaks in the steam system, up to and including the instantaneous circumferential rupture of the largest pipe in the steam system.

4. A steam generator tube failure.

The primary function of the ECCS is to remove the stored and fission product decay heat from the reactor core during accident conditions.

The ECCS is designed to tolerate a single active failure (short term) or single active or passive failure (long term). See Section 6.3.2.5 for details. It can meet its minimum required performance level with onsite or offsite electrical power.

The ECCS consists of the centrifugal charging, safety injection and residual heat removal pumps, accumulators, residual heat removal heat exchangers, Refueling Water Storage Tank along with the associated piping, valves, instrumentation and other related equipment.

The design bases for selecting the functional requirements of the ECCS are derived from Appendix K limits for fuel cladding temperature, etc., following any of the above accidents as delineated in 10CFR50.46. The subsystem functional parameters are selected to integrate so that the Appendix K requirements are met over the range of anticipated accidents and single failure assumptions.

Reliability of the ECCS has been considered in selection of the functional requirements, selections of the particular components and location of components and connected piping. The Equipment Specification for the SI/RHR pumps employed at Comanche Peak require them to be capable of performing their long-term cooling function for one year. Environmental qualification durations for ECCS equipment are described in Sections 3.11N and 3.11B. The same type of pump has been used extensively in other operating plants. Their function during recurrent normal cooldowns in such plants as Zion, D.C. Cook, and Trojan has successfully demonstrated their performance capability. Periodic inspections have further confirmed their long-term operability. Nevertheless, design provisions were included that would allow maintenance on either pump if it were necessary during long-term operation.

Redundant components are provided where the loss of one component would impair reliability. Valves are provided in series where isolation is desired and in parallel when flow paths are to be established for ECCS performance. Redundant sources of the ECCS actuation signal are available so that the proper and timely operation of the ECCS will not be inhibited. Sufficient

instrumentation is available so that a failure of an instrument will not impair readiness of the system. The active components of the ECCS are powered from separate buses which are energized from offsite power supplies.

In addition, redundant sources of auxiliary onsite power are available through the use of the emergency diesel generators to assure adequate power for all ECCS requirements. Each diesel is capable of driving all pumps, valves and necessary instruments associated with one train of the ECCS. Other auxiliary systems required to support operation of the ECCS include Component Cooling Water (CCW) for cooling of ECCS pumps and RHR heat exchanger (Section 9.2.2.2) and ESF ventilation for cooling ECCS motors (Section 9.4.5.1).

Spurious movement of a motor operated valve due to an electrical fault in the motor actuation circuitry, coincident with a loss of coolant accident (LOCA), has been analyzed and found to be a very low probability event. However, to comply with the NRC's present position on this issue, the applicant has committed to compliance with BTP- EICSB-18. Compliance is accomplished by providing a control board control power cut-off switch for each valve whose spurious movement could result in degraded ECCS performance. The motor operated valves on the ECCS that require power lockout in order to meet BTP ICSB-18 are identified in Table 6.3-3. The details of the power lockout design is described in Sections 6.3.2.2.12 and 7.6.4. Also see Figure 7.6-3 and elementary diagrams E1-0062, sheets 07, 08, 13, 16 thru 21, 26, 68 and 69 (FSAR Section 1.7). The applicant, nevertheless, reserves the right to retract this commitment in light of WCAP-8966 [See Section 1.6].

Administrative procedures will ensure that motor-operated ECCS valves are properly aligned and have power locked out to prevent spurious operation.

Westinghouse has prepared a Topical Report, WCAP-8966, "Evaluation of Mispositioned ECCS Valves," which substantiates and quantifies the Westinghouse position that spurious movement of a motor operated valve due to an electrical fault coincident with a LOCA is a very low probability event. The bases and assumptions along with the results of this analysis are described in WCAP-8966. Other component failure probabilities (e.g., from maintenance) were also considered in this analysis to justify spurious movement as a very low probability event.

The elevated temperature of the sump solution during recirculation is well within the design temperature of all ECCS components. In addition, consideration has been given to the potential for corrosion of various types of metals exposed to the fluid conditions prevalent immediately after the accident or during long term recirculation operations.

Environmental testing of ECCS equipment inside the Containment, which is required to operate following a LOCA, is discussed in Section 3.11N.

6.3.2 SYSTEM DESIGN

The ECCS components are designed such that a minimum of three accumulators, one charging pump, one safety injection pump, and one residual heat removal pump together with their associated valves and piping will assure adequate core cooling in the event of a design basis LOCA. The redundant onsite emergency diesels assure adequate emergency power to all electrically operated components in the event that a loss of offsite power occurs simultaneously with a LOCA, even assuming a single failure in the Emergency Power System such as the failure of one diesel to start.

All ECCS equipment, with the exception of the ECCS high head cold leg injection throttle valves, has been designed to perform its design function for at least one year without any periodic maintenance. The ECCS high head cold leg injection throttle valves have a service life of six months without any periodic maintenance, however, this service life exceeds the design function requirement for the high head injection flow path. Environmental qualification durations for ECCS equipment are described in Sections 3.11N and 3.11B.

6.3.2.1 Schematic Piping and Instrumentation Diagrams

Flow diagrams of the ECCS are shown in Figures 6.3-1 and 6.3-2. Figure 6.3-2 is provided for illustrative purposes and is based on enveloping conservative layout assumptions. Pertinent design and operating parameters for the components of the ECCS are given in Table 6.3-1. Information in this table has been derived from the actual CPNPP layout. The codes and standards to which the individual components of the ECCS are designed are listed in Table 17A-1.

The component interlocks used in different modes of system operation are listed below.

1. The safety injection signal is interlocked with the following components and initiates the indicated action:

   a. Centrifugal charging pumps start on "S" signal.

   b. Refueling Water Storage Tank suction valves to charging pumps open on "S" signal.

   c. High head safety injection isolation valves (parallel) open on "S" signal.

   d. Normal charging path valves close on "S" signal.

   e. Charging pump miniflow valves close on "S" signal. Alternate miniflow isolation valves (8511A and 8511B) open on “S” signal.

   f. Safety injection pumps start on "S" signal.

   g. The residual heat removal pumps start on "S" signal.

   h. Accumulator isolation valves receive a confirmatory "S" signal; however, these valves are open and have power removed above 1000 psig in accordance with Technical Specifications.

   i. Volume control tank outlet isolation valves close on "S" signal coincident with RWST suction valves full open.

   j. Refueling Water Storage Tank discharge isolation valves to the Spent Fuel Pool Cooling and Cleanup System close on "S" signal.

2. Switchover from the injection mode to recirculation involves the following interlocks.

   a. The suction valves from the sump open when a “S” signal is present and two-out-of-four low level transmitters indicate a low level in the Refueling Water Storage Tank.

   b. The safety injection pump and charging pump recirculation suction isolation valves can be opened provided that the safety injection pump miniflow lines have been isolated.

6.3.2.2 Equipment and Component Descriptions

The component design and operating conditions are specified as the most severe conditions to which each respective component is exposed during either normal plant operation, or during operation of the ECCS. For each component, these conditions are considered in relation to the code to which it is designed. By designing the components in accordance with applicable codes, and with due consideration for the design and operating conditions, the fundamental assurance of structural integrity of the ECCS components is maintained. Components of the ECCS are designed to withstand the appropriate seismic loadings in accordance with their safety class as given in Table 17A-1.

The major mechanical components of the ECCS follow and the specific component parameters are listed in Table 6.3-1.

6.3.2.2.1 Accumulators

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. During normal operation each accumulator is isolated from the RCS by two check valves in series. Should the RCS pressure fall below the accumulator pressure, the check valves open and borated water is forced into the RCS. One accumulator is attached to each of the cold legs of the RCS. Mechanical operation of the swing-disc check valves is the only action required to open the injection path from the accumulators to the core via the cold leg.

Connections are provided for remotely adjusting the level and boron concentration of the borated water in each accumulator during normal plant operation as required. Accumulator water level may be adjusted either by draining to the recycle holdup tank or by pumping borated water from the Refueling Water Storage Tank to the accumulator. Samples of the solution in the accumulators are taken periodically for checks of boron concentration.

Accumulator pressure is provided by a supply of nitrogen gas, and can be adjusted as required during normal plant operation; however, the accumulators are normally isolated from this nitrogen supply. Gas relief valves on the accumulators protect them from pressures in excess of design pressure.

The accumulators are located within the Containment but outside of the secondary shield wall which protects them from missiles.

Accumulator gas pressure is monitored by indicators and alarms. The operator can take action as required to maintain plant operation within the requirements of the Technical Specification covering accumulator operability. The accumulator borated water volume and nitrogen

cover-pressure will be provided as operability limits in the Technical Specifications prior to issuance of the operating license. Refer to Table 15.6-5 for the input SIS accumulator parameters utilized in the LOCA accident analysis.

6.3.2.2.2 Boron Injection Tank

The boron injection tank and all associated equipment has been deleted from the CPNPP design.

6.3.2.2.3 Boron Injection Surge Tank

The boron injection surge tank has been deleted from the CPNPP design.

6.3.2.2.4 Residual Heat Removal Pumps

In the event of a LOCA the residual heat removal pumps are started automatically on receipt of an "S" signal. The residual heat removal pumps deliver water to the RCS from the Refueling Water Storage Tank during the injection phase and from the containment sump during the recirculation phase. Each residual heat removal pump is a single stage, vertical position centrifugal pump.

A minimum flow bypass line is provided for the pumps to recirculate and return the pump discharge fluid to the pump suction should these pumps be started with their normal flow paths blocked. Once flow is established to the RCS, the bypass line is automatically closed. This line prevents deadheading of the pumps and permits pump testing during normal operation.

During the recirculation phase, the centrifugal charging pumps and the safety injection pumps are aligned to the discharge of the RHR pumps. If the RWST level continues to drop below the empty setpoint, the RHR pump discharge pressure will eventually close the check valve leading back to the RWST before air can be drawn through a postulated open motor-operated valve (MOV).

Each RHR pump contains a dedicated MOV in the suction line to the RWST. Each MOV is independently powered from a separate electrical train. The physical plant arrangement is such that, if one MOV fails to close and the sump isolation valve has opened, it is not possible for air to be drawn into an RHR pump through the open MOV. In addition, the redundant RHR train would not be affected by the single failure and would provide adequate plant protection.

In addition, the Emergency Operating Procedures includes the following caution:

If the RWST empty level alarm is received at any time subsequent to the accident, immediately stop any pumps still taking suction from the RWST, then complete the switchover and restart any pump which was stopped, beginning with the RHR pumps.

The residual heat removal pumps are discussed further in Section 5.4.7, and pump performance curve is given in Figure 6.3-3.

Related motor-operated valves are discussed further in Section 6.3.2.2.12, and manual actions required of the operator in the changeover from the injection to the recirculation modes is discussed in Section 6.3.2.8.

6.3.2.2.5 Centrifugal Charging Pumps

In the event of an accident, the charging pumps are started automatically on receipt of an "S" signal and are automatically aligned to take suction from the Refueling Water Storage Tank during injection. During recirculation, suction is provided from the residual heat removal pump discharge.

These pumps deliver flow to the RCS at the prevailing RCS pressure. Each centrifugal charging pump is a multistage diffuser design, barrel-type casing with vertical suction and discharge nozzles. To prevent water hammer, ECCS lines associated with the centrifugal charging pumps are maintained full of water since this piping is used for charging and makeup functions of the RCS during all phases of plant operation (refer to Section 9.3.4).

A minimum flow bypass line is provided on each pump discharge to recirculate flow to the pump suction after cooling via the seal water heat exchanger during normal plant operation. The minimum flow bypass line contains two valves in series which close on receipt of the safety injection "S" signal. This signal also opens the charging pump/Refueling Water Storage Tank suction valves and closes the valves to isolate the normal charging line and volume control tank to align the high head portion of the ECCS for injection. A charging pump suction line high point vent is provided to vent non-condensable gases to the VCT during normal operations. Redundant isolation valves in the line are interlocked with the VCT suction isolation valves to open and close on the same signals. An alternate minimum flow line is provided on each pump discharge line to recirculate flow to the RWST as described below. The charging pumps may be tested during power operation via the minimum flow bypass line or through normal charging flow path. A pump performance curve is given in Figure 6.3-4.

The two normally closed alternate miniflow isolation valves (8511A and 8511B) are required to open automatically in the presence of an “S” signal to provide a recirculation path to protect the centrifugal charging pumps from being deadheaded by high RCS pressure during accident conditions such as feed line breaks. When the valve strokes open, each centrifugal charging pump is connected to its associated alternate miniflow relief valve that discharges sufficient pump flow back to the RWST to prevent pump damage. Each normally closed valve is powered from the same train as its associated charging pump. A normally open isolation valve powered from the opposite train is provided in each line for redundant isolation. These valves are required to be closed manually prior to taking suction from the containment sump to prevent the alternate miniflow system from discharging contaminated sump water into the RWST through a leaking or stuck-open miniflow relief valve.

6.3.2.2.6 Safety Injection Pumps

In the event of an accident the safety injection pumps are started automatically on receipt of an "S" signal.

These pumps deliver water to the RCS from the Refueling Water Storage Tank during the injection phase and from the containment sump via the residual heat removal pumps during the recirculation phase. Each intermediate head safety injection pump is driven directly by an induction motor.

A minimum flow bypass line is provided on each pump discharge to recirculate flow to the Refueling Water Storage Tank in the event that the pumps are started with the normal flow paths

blocked. This line may also be used for testing during normal plant operation. Two parallel valves in series with a third (SI Pump Mini-Flow Valve) downstream of a common header, are provided in this line. These valves are manually closed from the Control Room as part of the ECCS realignment from the injection to the recirculation mode. A pump performance curve is shown in Figure 6.3-5.

After the SI Pump Mini-Flow Valve is brought to the required open or closed position by the "OPEN-CLOSE" control switch, the power is removed by a key operated power cut off switch. The key is removable in the "OFF" position only. Both these switches are located on the control board in the same module. Placing the key operated switch in the "OFF" position disconnects both the hot and neutral legs of the control power supply for the Motor Operated Valve starter coils, not just the control circuitry on the main control board. This switch however does not remove 480V power directly from the valve operator. To do so would require bringing 480V power to the main control board where the present circuit voltages are limited to nominal 120V AC and 125V DC and would violate the intent of Regulatory Guide 1.75, paragraph 12 (Rev. 1, January 1975).

6.3.2.2.7 Boron Injection Recirculation Pumps

These pumps have been deleted from the CPNPP design.

6.3.2.2.8 Residual Heat Exchangers

The residual heat exchangers are conventional shell and U-tube type units. During normal cooldown operation, the residual heat removal pumps recirculate reactor coolant through the tube side while component cooling water flows through the shell side. During emergency core cooling recirculation operation, water from the containment sump flows through the tube side. The tubes are seal welded to the tubesheet.

A further discussion of the residual heat exchangers is provided in Section 5.4.7.

6.3.2.2.9 Valves

Design parameters for all types of valves used in the ECCS are given in Table 6.3-1.

Design features employed to minimize valve leakage include:

1. Where possible, packless valves are used.

2. Other valves which are normally open, except check valves and those which perform a control function, are provided with backseats to limit stem leakage.

3. Normally closed globe valves are installed with recirculation fluid pressure under the seat to prevent stem leakage of recirculated (radioactive) water.

4. Relief valves are enclosed; i.e., they are provided with a closed bonnet.

6.3.2.2.9.1 Motor Operated Valves

The seating design of all motor operated gate valves is of the crane flexible wedge design.

This design releases the mechanical holding force during the first increment of travel so that the motor operator works only against the frictional component of the hydraulic unbalance on the disc and the packing box friction. The disc is guided throughout the full disc travel to prevent chattering and to provide ease of gate movement. The seating surfaces are hard faced to prevent galling and to reduce wear.

Where a gasket is employed for the body-to-bonnet joint, it is either a fully trapped, controlled compression, spiral wound gasket with provisions for seal welding, or it is of the pressure seal design with provisions for seal welding. The valve stuffing boxes are designed with a lantern ring leakoff connection with a minimum of a full set of packing below the lantern ring and a minimum of 1/2 of a set of packing above the lantern ring. A full set of packing is defined as a depth of packing equal to 1-1/2 times the stem diameter. The following exceptions to these general guidelines exist: Motor operated valves two inches and under in size do not have a leak connection, but have a minimum of a full set of stem packing. Also, motor operated RHR pump minimum flow bypass 3-inch globe valves FCV-0610 and FCV-0611are supplied without “provisions for seal welding” (weld preparation of the bonnet flanges).

The motor operator incorporates a "hammer blow" feature that allows the motor to impact the discs away from the backseat upon opening or closing. This "hammer blow" feature not only impacts the disc but allows the motor to attain its operational speed prior to impact; thus, providing a more positive opening and closing mechanism. Valves which must function against system pressure are designed such that they function with a pressure drop equal to full system pressure across the valve disc. This feature is an accepted commercial design, not limited to application within the nuclear industry. Considerable valve operating experience, and Westinghouse's valve qualification and operability programs, have demonstrated the reliability of the valve design feature. Surveillance procedures incorporated in Technical Specifications for ECCS valves ensure continued valve operability, including the "hammer blow" feature.

6.3.2.2.9.2 Manual Globes, Gates and Check Valves

Gate valves employ a wedge design and are straight through. The wedge is either split or solid. All gate valves have backseats and outside screws and yokes.

Globe valves, "T" and "Y" style are full ported with outside screw and yoke construction.

Check valves are spring loaded, lift piston types for sizes 2 inches and smaller, except for 1SI-8819D, 2SI-8819A, and 2SI-8819D, which are nozzle check valves. Check valves are swing type for size 2-1/2 inches to 4 inches and tilting disc type for size 4 inches and larger. Stainless steel check valves have no penetration welds other than the inlet, outlet and bonnet. The check hinge is serviced through the bonnet.

The stem packing and gasket of the stainless steel manual globe and gate valves are similar to those described above for motor operated valves. Carbon steel manual valves are employed to pass nonradioactive fluids only and therefore do not contain the double packing and seal weld provisions.

6.3.2.2.9.3 Accumulator Check Valves (Swing-disc)

The accumulator check valve is designed with a low pressure drop configuration with all operating parts contained within the body.

Design considerations and analyses which assure that leakage across the check valves located in each accumulator injection line will not impair accumulator availability are as follows:

1. During normal operation the check valves are in the closed position with a total differential pressure across the discs of both check valves of approximately 1650 pounds per square inch (psi). Since the valves remain in this position except for testing or when called upon to open following an accident, and are therefore not subject to the abuse of flowing operation or impact loads caused by sudden flow reversal and seating, they do not experience significant wear of the moving parts, and are expected to function with minimal backleakage. This backleakage can be checked via the test connection as described in Section 6.3.4.

2. Periodically, the check valves are tested for leakage as described in Section 6.3.4.2. This test confirms the seating of the disc and whether or not there has been an increase in the leakage since the last test.

3. The experience derived from the check valves employed in the emergency injection systems indicate that the system is reliable and workable; check valve leakage has not been a problem. This is substantiated by the satisfactory experience obtained from operation of Robert Emmett Ginna (Docket No. 50-244) and subsequent plants where the usage of check valves is identical to the CPNPP.

4. The accumulators can accept some inleakage from the RCS without affecting availability. The availability and operability of the SIS accumulator tanks will be unaffected as long as the accumulator in-leakage does not violate the accumulator pressure/volume technical specification limits. Additionally, accumulator in-leakage is considered when determining RCS identified leakage, the total of which is limited by the technical specifications.

6.3.2.2.9.4 Relief Valves

Relief valves are installed in various sections of the ECCS to protect lines which have a lower design pressure than the RCS. The valve stem and spring adjustment assembly are isolated from the system fluids by a bellows seal between the valve disc and spindle. The closed bonnet provides an additional barrier for enclosure of the relief valves. Table 6.3-2 lists the systems relief valves with their capacities and setpoints.

6.3.2.2.9.5 Butterfly Valves

Each main residual heat removal line has an air operated butterfly valve which is normally open and is designed to fail in the open position. The actuator is arranged such that air pressure on the diaphragm overcomes the spring force, causing the linkage to move the butterfly to the closed position. Upon loss of air pressure, the spring returns the butterfly to the open position. These valves are left in the full open position during normal operation to maximize flow from this system to the RCS during the injection mode of the ECCS operation. These valves are used during normal Residual Heat Removal System (RHRS) operation to control cooldown flow rate.

Each residual heat removal heat exchanger bypass line has an air operated butterfly valve which is normally closed and is designed to fail closed. These valves are used during normal cooldown to avoid thermal shock to the residual heat exchanger.

6.3.2.2.10 Net Positive Suction Head

Available and required net positive suction head for ECCS charging and safety injection pumps are shown in Table 6.3-1. This Table used the actual CPNPP Unit 1 station piping layout to determine the NPSH available at runout conditions. Conservative assumptions have been included (e.g., RWST at minimum level and all other safeguard pumps at maximum runout flow) to minimize the NPSH available.

The safety intent of Regulatory Guide 1.1 is met by the design of the ECCS such that adequate net positive suction head is provided to system pumps. In addition to considering the static head and suction line pressure drop, the calculation of available net positive suction head in the recirculation mode assumes that the vapor pressure of the liquid in the sump is equal to the Containment ambient pressure. This assures that the actual available net positive suction head is always greater than the calculated net positive suction head.

The calculation of available net positive suction head is as follows:

$$(\text{Net positive suction head})_{actual} = (h)_{ambient\ pressure}$$

$$- (h)_{vapor\ pressure} + (h)_{static\ head} - (h)_{loss}$$

$$(\text{Net positive suction head})_{calc} = (h)_{static\ head} - (h)_{loss}$$

The most limiting ECCS condition for available NPSH is with the charging pumps aligned to the RWST, minimum RWST level, and maximum runout for both charging pumps.

ECCS pump specifications include a specified maximum required NPSH which the pump is required to meet. Adequate net positive suction head is shown to be available for all pumps as follows:

1. Residual heat removal pumps

   The net positive suction head of the residual heat removal pumps is evaluated for normal plant cooldown operation, and for both the injection and recirculation modes of operation for the design basis accident. Recirculation operation gives the limiting net positive suction head requirement, and the net positive suction head available is determined from the Containment sump level relative to the pump elevation, the clean strainer head loss, and the pressure drop in the suction piping from the sump to the pumps. The net positive suction head evaluation is based on one residual heat removal pump delivering to two Reactor Coolant System loops and both safety injection and both charging pump suctions.

   The NPSH margin is calculated based on a clean strainer and minimum containment water levels during full sump recirculation. The design basis debris head loss is determined by prototypical testing of a full size strainer with the design basis debris load as described in Section 6.2.2.3.3 scaled to the test configuration. This testing has shown that significant NPSH margin remains after the design basis debris head loss is subtracted from the clean strainer NPSH margin.

2. Safety injection and centrifugal charging pumps

The net positive suction head for safety injection pumps and the centrifugal charging pumps is evaluated for both the injection and recirculation modes of operation for the design basis accident. The end of injection mode of operation gives the limiting net positive suction head available. The net positive suction head available is determined from the elevation head and vapor pressure of the water in the refueling water storage tank, which is at atmospheric pressure, and the pressure drop in the suction piping from the tank to the pumps. When a pre-determined low refueling water storage tank level is reached the safety injection and charging pumps are manually aligned to take suction from the residual heat removal pump discharge headers. The net positive suction head requirements of these pumps are therefore satisfied by the discharge head of the residual heat removal pumps.

6.3.2.2.11 Accumulator Motor Operated Valve Controls

As part of the plant shutdown administrative procedures, the operator is required to close these valves. This prevents a loss of accumulator water inventory to the RCS and is done when the accumulators are no longer required operable by the Technical Specifications. The redundant pressure and level alarms on each accumulator would remind the operator to close these valves, if any were inadvertently left open. Control power is disconnected to these valves after closure by locking open the valve breakers.

During plant startup, the operator is instructed via procedures to energize and open these valves and remove power when the accumulators are required operable by the Technical Specifications. Monitor lights in conjunction with an audible alarm will alert the operator should any of these valves be left inadvertently closed once the RCS pressure increases beyond the safety injection unblock setpoint.

The accumulator isolation valves are not required to move during power operation or in a post accident situation. For a discussion of limiting conditions for operation and surveillance requirements of these valves, refer to Section 3.5.1 of the Technical Specifications.

For further discussions of the instrumentation associated with these valves refer to Sections 6.3.5, 7.3.1 and 7.6.4.

6.3.2.2.12 Motor Operated Valves and Controls

Remotely operated valves for the injection mode which are under manual control (i.e., valves which normally are in their ready position and do not require a safety injection signal) have their positions indicated on a common portion of the control board. If a component is out of its proper position, its monitor light will indicate this on the control panel. At any time during operation when one of these valves is not in the ready position for injection, this condition is shown visually on the board. Table 6.3-3 is a listing of motor operated isolation valves in the ECCS showing interlocks, automatic features and position indications.

The ECCS delivery lag times are given in Chapter 15. The accumulator injection time varies as the size of the assumed break varies since the RCS pressure drop will vary proportionately to the break size.

Spurious movement of a motor operated valve due to an electrical fault in the motor actuation circuitry, coincident with a LOCA, has been analyzed and found to be a very low probability event [WCAP-8966]. However, to comply with the NRC's present position on this issue, the applicant has committed to compliance with BTP-EICSB-18. Compliance is accomplished by providing a control board control power cut-off switch for each valve whose spurious movement could result in degraded ECCS performance. All valves that require removal of power shall be listed in the Technical Specifications per BTP-EICSB-18.

The position in which those valves are located (open or closed) and locked into position are those which ensure ECCS operability. The consequences of a LOCA under those conditions are therefore as described in Chapter 15.

Administrative procedures will require control room power lockout during normal operation with the motor operated valves in their correct position. With these design provisions any concern over damage to both safety injection pumps due to spurious valve movement is eliminated.

Further, subsequent to an accident, power can easily be reinstituted and the valve repositioned as required during the switchover from the injection to recirculation mode. Valve 8806 is in series with check valve 8926 which closes when valves 8804A and 8804B are opened to supply the safety injection pumps from the RHR. This isolates the RWST. Thus, a single failure of valve 8806 to close will not result in a loss of core cooling or a path that permits the release of radioactive material from the containment to the environment.

Administrative controls, procedures, and checklists are employed to assure that manual valves are always restored to their correct position and that lockable valves are locked in their correct position during operation (e.g.) SI-047 and SI-048 are locked open).

The following manually operated valves which could degrade ECCS operation if moved to the incorrect position are locked in their correct position during operation.

8822 A, B, C & D
8810 A, B, C & D

8717

8816 A, B, C & D
SI-047
SI-048

Since these valves are not motor-operated, they do not fall under the requirements of RSB BTP 6-1, and are not subject to single active failure.

The above design and administrative provisions are adequate to ensures ECCS valves are maintained in the correct position.

Periodic visual inspection and operability testing of the motor operated valves in the ECCS insures that there is no potential for impairment of valve operability due to boric acid crystallization which could result from valve stem leakage.

6.3.2.3 Applicable Codes and Classifications

Applicable industry codes and classifications for ECCS components are discussed in Section 3.2.

6.3.2.4 Materials Specifications and Compatibility

Materials employed for components of the ECCS are given in Table 6.3-4. Materials are selected to meet the applicable material requirements of the codes in Table 3.2-2 and the following additional requirements:

1. All parts of components in contact with borated water are fabricated of or clad with austenitic stainless steel or equivalent corrosion resistant material.

2. All parts of components in contact (internal) with sump solution during recirculation are fabricated of austenitic stainless steel or equivalent corrosion resistant material.

3. Valve seating surfaces are hard faced with Stellite Number 6 or manufactured from materials suitable to prevent galling and to reduce wear.

4. Valve stem materials are selected for their corrosion resistance, high tensile properties, and resistance to surface scoring by the packing.

6.3.2.5 System Reliability

Reliability of the ECCS is considered in all aspects of the system from initial design to periodic testing of the components during plant operation.

The ECCS is a two train, fully redundant standby safeguard feature. The system has been designed and proven by analysis to withstand any single credible active failure during injection, or active or passive failure during recirculation and maintain the performance objectives desired in Section 6.3.1. This capability is demonstrated by the failure mode and effects analysis (FMEA) presented in Table 6.3-10. Operator error although not specifically discussed, is inherently addressed in the FMEA and the compliance with BTP-EICSB-18. Failure of components connected to the ECCS are addressed in either the FMEA for the ECCS (e.g., LCV 112 B&C or MOV 8105) or in other sections of the FSAR (e.g., see Section 9.2.1 and 9.2.2 for failure analysis of the station service water system and the component cooling water system, respectively). Two trains of pumps, heat exchangers, and flow paths are provided for redundancy as only one train is required to satisfy the performance requirements. The initiating signals for the ECCS are derived from independent sources as measured from process (e.g., low pressurizer pressure) or environmental variables (e.g., Containment pressure). Redundant as well as functionally independent variables are measured to initiate the safeguards signals. Each train is physically separated and protected where necessary so that a single event cannot initiate a common failure. Power sources for the ECCS are divided into two independent trains supplied from the emergency buses from offsite power. Sufficient diesel generating capacity is maintained onsite to provide required power to each train. The diesel generators and their auxiliary systems are completely independent and each supplies power to one of the two ECCS trains.

The reliability program extends to the procurement of the ECCS components such that only designs which have been proven by testing and/or past use in similar or more severe

applications are acceptable for use. The quality assurance program as described in Chapter 17 assures receipt of components only after manufacture and test to the applicable codes and standards.

The preoperational testing program assures that the systems, as designed and constructed, will meet the functional requirements as calculated in design.

To prevent the occurrence of water hammer in the ECCS lines, the lines are maintained full of water at all times. Refer to Section 6.3.3.7 for a discussion of ECCS piping between containment penetrations and the RWST, and Section 6.3.2.2.5 for a discussion of ECCS lines associated with the centrifugal charging pumps. The water solid condition of the remaining ECCS piping is assured each time the operability of the system is tested. Test procedures ensure that at the conclusion of the test, the system is left in the water solid condition. The ECCS is designed with the ability for on-line testing of most components so the availability and operational status can be readily determined.

In addition to the above, the integrity of the ECCS is assured through examination of critical components during the routine inservice inspection.

1. Active Failure Criteria

   The ECCS is designed to accept a single failure following the incident without loss of its protective function. The system design will tolerate the failure of any single active component in the ECCS itself or in the necessary associated service systems at any time during the period of required system operations following the incident.

   A single active failure analysis is presented in Table 6.3-5 and demonstrates that the ECCS can sustain the failure of any single active component in either the short or long term and still meet the level of performance for core cooling. For ECCS performance evaluation for a loss of coolant accident (LOCA), the single failure assumed is the loss of a low head SI (RHR) pump for a large break LOCA and the loss of an SI train for a small break LOCA. See Section 15.6.5.3.2 for a discussion of the most limiting single failure assumed.

   Since the operation of the active components of the ECCS following a steam line rupture is identical to that following a LOCA, the same analysis is applicable and the ECCS can sustain the failure of any single active component and still meet the level of performance for the addition of shutdown reactivity.

2. Passive Failure Criteria

   The following philosophy provides for necessary redundancy in component and system arrangement to meet the intent of the General Design Criteria on single failure as it specifically applies to failure of passive components in the ECCS. Thus, for the long term, (i.e., after initial switchover from cold leg recirculation to hot leg recirculation) the system design is based on accepting either a passive or an active failure.

A single passive failure analysis is presented in Table 6.3-6. It demonstrates that the ECCS can sustain a single passive failure during the long term phase and still retain an intact flow path to the core to supply sufficient flow to maintain the core covered and effect the removal of decay

heat. The procedure followed to establish the alternate flow path also isolates the component which failed. Figure 6.3-2 is a simplified illustration of the ECCS. The notes provided with Figure 6.3-2 contain information relative to the operation of the ECCS in its various modes. The modes of operation illustrated are full operation of all ECCS components, cold leg recirculation with only residual heat removal pump number 2 operating, and hot leg recirculation with residual heat removal pump number 1 operating. These are representative of the operation of the ECCS during accident conditions.

6.3.2.5.1 Redundancy of Flow Paths and Components for Long Term Emergency Core Cooling

In design of the ECCS, the following criteria was utilized:

1. During the long term cooling period following a LOCA, the emergency core cooling flow paths shall be separable into two subsystems, either of which can provide minimum core cooling functions and return spilled water from the floor of the Containment back to the RCS.

2. Either of the two subsystems can be isolated and removed from service in the event of a leak outside the Containment.

3. Adequate redundancy of check valves is provided to tolerate failure of a check valve during the long term as a passive component.

4. Should one of these two subsystems be isolated in this long term period, the other subsystem remains operable.

5. Provisions are also made in the design to detect leakage from components outside the Containment, to collect this leakage and to provide for maintenance of the affected equipment. Specific provisions are available to maintain major components (e.g., RHR pump and heat exchanger, SI pumps, charging pumps) as well as isolation valves, high point vents and drains during recovery from a LOCA. These provisions assist in the reduction of radiation exposure levels by providing a means for isolating, draining and flushing components which may require maintenance and connected piping. Exposure limits are also reduced by the building layout; it provides shielding between individual components and adequate ventilation of equipment cubicles. Isolation valves are provided with back seats to facilitate stempacking replacement and to limit maintenance exposure.

Thus, for the long term emergency core cooling function, adequate core cooling capacity exists with one flow path removed from service.

6.3.2.5.2 Subsequent Leakage from Components in Safeguards Systems

With respect to piping and mechanical equipment outside the Containment, considering the provisions for visual inspection and leak detection, leaks will be detected before they propagate to major proportions. A review of the equipment in the system indicates that the largest sudden leak potential would be the sudden failure of a pump shaft seal. Evaluation of the shaft leak rate assuming the complete failure of the primary seal, with only the presence of a seal retention ring

(or throttle bushing) for the RHR pump design, showed a leak rate significantly less than 50 gallons per minute (gpm).

Assuming a design basis passive failure of 50 gpm occurs, the water level in the sump will rise at a rate of approximately five inches per minute.

The plant operator receives warning by Control Room alarms, as follows:

1. The first floor drain sump pump will start when the water level reaches the Hi-1 setpoint, less than two minutes after the design basis passive failure occurs. The first level alarm (Hi-1) alerts the Control Room operator that a Safeguard Buildings sump pump has been started.

2. The second floor drain sump pump will start when the sump water level reaches the Hi-2 setpoint. Assuming the first pump failed to start, the second level alarm (Hi-2) alerts the Control Room operator that a second Safeguards Building sump pump has been started.

3. Assuming at least one of the two pumps start, the sump water level will cycle at least once every 5 minutes. This alarm cycle alerts the Control Room operator that a major leak may have occurred and an operator is dispatched to identify the affected train.

After the faulted ECCS train is identified, it can be isolated from the Control Room by operator action. This is done by stopping the corresponding pumps and isolating the respective RHR or containment spray suction lines with appropriate remote operated valves.

Piping leaks, valve packing leaks, or flange gasket leaks have been of a nature to buildup slowly with time and are considered less severe than the pump seal failure.

Larger leaks in the ECCS are prevented by the following:

1. The piping is classified in accordance with ANS Safety Class 2 and receives the ASME Class 2 quality assurance program associated with this safety class.

2. The piping, equipment and supports are designed to ANS Safety Class 2 seismic classification permitting no loss of function for the safe shutdown earthquake.

3. The system piping is located within a controlled area on the plant site.

4. The piping system receives periodic pressure tests and is accessible for periodic visual inspection.

5. The piping is austenitic stainless steel which, due to its ductility, can withstand severe distortion without failure.

Based on this review, the design of the Auxiliary Building and related equipment is based upon handling of leaks up to a maximum of 50 gpm. Means are also provided to detect and isolate such leaks in the emergency core cooling flow path within 30 minutes. See Section 9.3.3.5 for additional details on leak detection.

6.3.2.5.3 Lag Times

Lag times for initiation and operation of the ECCS is limited by pump startup time and consequential loading sequence of these motors onto the safeguard buses. Most valves are normally in the position conducive to safety; therefore valve opening time is not considered for these valves. In the case of an accident coincident with a blackout, a 10 second delay is assumed for diesel startup; then pumps are loaded according to the sequencer. The charging pumps and all valves will be applied to the buses in 10 seconds, the safety injection pumps will start in 15 seconds and the residual heat removal pumps in 20 seconds. These times refer to the maximum delay after receipt of an "S" signal assuming loss of offsite power. If there is no loss of offsite power, the same pump starting sequence is followed after a one second sequencer delay with the first valve load being started upon receipt of the "S" signal. See Section 8.3.1.1.5.3.

6.3.2.5.4 Potential Boron Precipitation

Boron precipitation in the reactor vessel is prevented by a backflush of cooling water through the core to reduce boiloff and resulting concentration of boric acid in the water remaining in the reactor vessel.

Three flow paths are available for hot leg recirculation of sump water. Each safety injection pump can discharge to two hot legs with suction taken from the residual heat removal pump discharge. In addition the residual heat removal pumps can discharge through the common cross connect line and inject water through two hot legs. Loss of one pump or one flow path will not prevent hot leg recirculation since two redundant flow paths are available for use.

6.3.2.5.5 Submerged Valve Motors

An evaluation of the potential for the submersion of ECCS valve motors concludes that all motors are above the local maximum post-accident water level.

The RHR suction isolation valves (Numbers 1-8701A, 1-8701B, 1-8702A and 1-8702B) are located inside the Containment at approximately elevation 817 ft. This elevation is above the local maximum post-accident water level.

6.3.2.6 Protection Provisions

The provisions taken to protect the system from damage that might result from dynamic effects are discussed in Section 3.6N. The provisions taken to protect the system from missiles are discussed in Section 3.5. The provisions to protect the system from seismic damage are discussed in Sections 3.7N, 3.9N and 3.10N. Thermal stresses on the RCS are discussed in Section 5.2.

6.3.2.7 Provisions for Performance Testing

Test lines are provided for performance testing of the ECCS as well as individual components. These test lines and instrumentation are shown in Figure 6.3-1. All pumps have miniflow lines which may be used for testing operability. Additional information on testing can be found in Section 6.3.4.2.

6.3.2.8 Manual Actions

No manual actions are required of the operator for proper operation of the ECCS during the injection mode of operation. Only limited manual actions are required by the operator to realign the system for the cold leg recirculation mode of operation, and, after approximately 3 hours, the hot leg recirculation mode of operation. These actions are delineated in Table 6.3-7.

The changeover from the injection mode to recirculation mode is initiated automatically and completed manually by operator action from the Control Room. The ECCS switchover from safety injection to cold leg recirculation is initiated automatically upon receipt of the RWST switchover initiation (RWST low-low level) signal, and is completed via timely operator action at the main control board. Protection logic is provided to automatically open the two Safety Injection System (SIS) recirculation sump isolation valves (8811 A&B), when two of four Refueling Water Storage Tank (RWST) level channels indicate an RWST level less than a low-low level setpoint, in conjunction with the engineered safeguards actuation signal ("S" signal). This automatic action aligns the suction of the two Residual Heat Removal (RHR) pumps to the containment recirculation sump to ensure continued availability of a suction source. It should be noted that the RHR pumps continue to operate during this changeover from injection mode to recirculation mode.

The two charging pumps and the two safety injection pumps would continue to take suction from the RWST, following the above automatic action, until manual operator action is taken to align these pumps in series with the residual heat removal pumps.

The RWST low-low level protection logic consists of four level channels with each level channel assigned to a separate process control protection set. Four RWST level transmitters provide level signals to corresponding normally deenergized level channel bistables. Each level channel bistable would be energized on receipt of an RWST low-low level signal.

A two out of four coincident logic is utilized in both protection cabinets A and B to ensure a trip signal in the event that two of the four level channel bistables are energized. This trip signal, in conjunction with the "S" signal, provides the actuation signal to automatically open the corresponding containment sump isolation valves.

The low-low RWST level signal is also alarmed to inform the operator to initiate the manual action required to realign the charging and safety injection pumps for the recirculation mode. The manual switchover sequence that must be performed by the operator is delineated in Table 6.3-7.

The switchover procedure is designed to minimize the time required to align the ECCS pumps to the containment sump, utilizing switchover steps in which the operator simultaneously switches both trains of the ECCS from injection to recirculation. As the switchover actions are completed, RWST outflow is reduced. Manual actions 1 thru 6 of Table 6.3-7 must be performed following switchover initiation prior to loss of the RWST transfer allowance to ensure that all ECCS pumps are protected with suction flow available from the containment recirculation sump.

Following the automatic and manual switchover sequence, the two residual heat removal pumps would take suction from the containment recirculation sump and deliver borated water directly to the RCS cold legs. A portion of the number 1 residual heat removal pump discharge flow would be used to provide suction to the two charging pumps which would also deliver directly to the RCS cold legs. A portion of the discharge flow from the number 2 residual heat removal pump

would be used to provide suction to the two safety injection pumps which would also deliver directly to the RCS cold legs. As part of the manual switchover procedure (Table 6.3-7, Action 6), the suctions of the safety injection and charging pumps are cross connected so that one residual heat removal pump can deliver flow to the RCS and both safety injection and charging pumps, in the event of the failure of the second residual heat removal pump.

The minimum delay between the RWST "low" level signal and the "low-low" level signal, with all systems operating (based on maximum allowable Technical Specification instrument errors in each of the four RWST level channels involved is greater than 10 minutes. Operator action to initiate ECCS switchover is not required until 30 seconds later (following automatic opening of the recirculation sump isolation valves (8811A & B).

Thus, operator action to initiate ECCS switchover is not required prior to 10 minutes after event initiation.

The RWST switchover is then performed by transferring the ECCS to cold leg recirculation followed by transferring containment spray to recirculation.

The time available for switchover is dependent on the flowrate out of the RWST as the switchover manual actions are performed. As valves are repositioned, the flowrate out of the RWST is reduced in magnitude. In order to analyze the shortest time available for switchover, the following conservative bases were established.

1. The minimum ECCS transfer allowance available between Low-Low and Empty is greater than 117,760 gallons.

2. Containment and RCS pressures for large break conditions are conservatively assumed to be 0 psig; thus, no credit is taken for the reduction in RWST outflow that will result with higher containment and RCS pressures following a large break. The same assumption is made for the small break conditions, except that RCS pressure is assumed to be greater than RHR pump shutoff head resulting in no RHR pump flow to the RCS for small break conditions.

3. Flow out of the RWST during switchover includes allowances for both pumped flow to the RCS and containment and the possibility of gravity flow (backflow) to the containment sump based on the 0 psig containment pressure assumption and ECCS operating conditions. Specific flowrate allowances are addressed in Table 6.3-11.

4. Flowrate out of the RWST for the worst single failure condition is determined assuming one of the RWST isolation valves (8812A or B) fails to close on demand. This single failure maximizes RWST outflow during switchover. Flowrates out of the RWST assume no operator corrective action to mitigate the single failure (i.e., stop the affected RHR pump and close the appropriate sump isolation valves).

5. Containment flood level above RWST Low-Low plus instrument setpoint uncertainty is assumed constant throughout ECCS switchover to minimize sump flow.

6. Containment flood level above RWST 6% indication is conservatively assumed constant throughout containment spray switchover to minimize sump flow.

7. Flowrate out of the RWST for the worst containment spray single failure condition is determined assuming one of the sump isolation valves (HV-4782 or HV-4783) fails to open on demand. This single failure is bounded by the single failure in the ECCS. Flowrate out of the RWST assumes the operator will stop the affected containment spray pump.

8. The operator initiates the opening of the sump to containment spray pump isolation valves (HV-4782 and HV-4783) at 6% after receipt of the Empty Alarm (at 9%). There is sufficient volume between the 6% indication minus instrument uncertainty and the minimum level for pump suction for the tank isolation valves to fully close.

Sufficient NPSH is available at the time of assumed changeover of the ESF pumps; the single RHR pump (due to the single failure assumption) and the four containment spray pumps continue to draw suction from the RWST. The RHR pump minimum NPSH requirement is below the elevation of the RWST discharge nozzle; therefore, the operator has adequate time to shut down the RHR pump associated with the failed valve. The NPSH requirement for the containment spray pumps is also below the elevation of the RWST discharge nozzle. A monitor light indication is provided to the operator during the recirculation mode when the valve is not in its proper position.

Based on the above criteria, the calculated flowrates out of the RWST as a function of switchover manual action are itemized in Table 6.3-11 for a large break with a single failure, which constitutes the condition where RWST outflow is greatest. Table 6.3-11 also identifies the operator action time assumed, as well as the change in RWST volume, per switchover step. Analyzing the flowrate out of the RWST for the large LOCA with the worst single failure indicates that less than 117,760 gallons are consumed prior to the completion of RWST switchover manual actions. This volume is less than the ECCS transfer allowance which ensures that the switchover steps necessary to protect all ECCS pumps can be accomplished before the transfer allowance is depleted.

See Section 7.5 for process information available to the operator in the control room following an accident. For further information on RHR pumps, and related operator action, see Section 6.3.2.2.4.

Although startup and shutdown are transient events and accidents are not to be considered coincidentally, the following protection is afforded the plant for a secondary side pipe rupture. Safety injection actuation on low pressurizer pressure and low steam line pressure may be manually blocked when NSSS pressure falls below P-11. Specific blocking features are addressed in Section 7.3.2.2.6. Between P-11 and 1000 psig, all safety equipment in the ECCS is aligned for safety injection with the exception of the disarmed pressurizer and steam line pressure safety injection signals. At this time, the operator is monitoring the pressurizer pressure and water level and RCS temperature per the plant cooldown procedure. Also, Technical Specifications impose minimum temperature requirements as a function of pressure on the operator to avoid exceeding NDT limitations. The operator, as a matter of course, has available the pressurizer pressure and water level and RCS temperature measurements on the control board strip chart recorders.

For large LOCAs, sufficient mass and energy is released to the containment to automatically actuate safety injection when the containment high pressure setpoint is reached. At this time, the operator is alerted of the occurrence of a LOCA by the following safety-related indications:

1. Loss of pressurizer level,

2. Rapid decrease of RCS pressure,

3. Containment pressure increase.

In addition, the following indications are normally available to the operator at the control board:

1. Radiation alarms inside containment,

2. Sump water level increasing,

3. Accumulator water levels and pressure decreasing,

4. ECCS valve and pump position and status light in ECCS energized indication. Annunciators will light as safeguards equipment becomes energized,

5. Flow from ECCS pumps is indicated on control board.

For small LOCA's, approximately less than two inches in diameter, where the containment high pressure setpoint may not be reached, the operator observes the safety-related indications plus the first two normally available indications. In addition, there is a charging flow/letdown mismatch which provides the operator with another indication of leakage from the RCS. Since the operator is observing the pressurizer level and is getting additional indications that a LOCA has occurred, the operator immediately initiates manual safety injection. As noted in WCAP-8356, ECCS Plant Sensitivity Studies, the time to uncover the core following a small break is relatively long (e.g., greater than 10 minutes for a 2-inch break). The operator, therefore, has sufficient time to manually initiate safety injection.

At less than 1000 psig, the operator closes and locks out the safety injection accumulator isolation valves. At less than 350 F, the operator renders the high head safety injection pumps inoperable in accordance with Technical Specifications. At this time, at least one low head safety injection pump and at least one charging pump are available from either automatic or manual safety injection actuation. At less than 350 F, the operator aligns the RHR System. The valves in the line from the RWST are closed.

The significance of these actions on the mitigation of a LOCA when power is locked out to the isolation valves is that between 1000 psig and reaching 350 F, a portion of the ECCS can be actuated automatically (containment hi-1 signal) or manually by the operator. The equipment that can be energized are two low head safety injection and two high head charging pumps, two high head safety injection pumps and, subsequent to the operator reinstituting power to the accumulator isolation valves.

Below 350 F, the system is in the RHR cooling mode. The operator realigns the RHR system per plant startup procedure; places all safeguards systems valves in the required positions for ECCS operation; and then manually actuates the individual ECCS components.

Comparing plant cooldown and heatup, the limiting case for a LOCA is during cooldown rather than heatup because the core decay heat generation is higher. The ECCS analysis presented in Chapter 15 conforms to the acceptance criteria of 10CFR50.46 (initiation of the LOCA is at

100.6% of full licensed power rating for Unit 1 and Unit 2 with corresponding RCS conditions), and is more limiting than a LOCA during shutdown, since:

1. A LOCA initiated during shutdown has reduced decay heat generation; the reactor would have been at zero power for an extended period of time.

2. The core stored energy during shutdown is reduced due to the RCS isothermal condition at a reduced temperature.

3. The energy content of the RCS is lower.

Furthermore, the probability of an occurrence of a LOCA during this time along with the critical flaw size needed to rupture the RCS piping at reduced pressure is considered to be incredible. (Note: Unit 1 LOCA initiation is at 102% of full licensed power until completion of 1RF09).

Emergency operating procedures are written such that the operator is permitted to manually reset the safety injection signal after two minutes following protection system actuation. This enables the operator to shut down a safeguards pump or to change the position of a valve receiving an SIS signal, as necessary. In the unlikely event that a blackout occurs following an SIS reset, ECCS valve positions remain unchanged; the operator only needs to depress the manual safety injection switches to restart safety injection. Manual resets are discussed in greater detail in Section 7.3.2.2.6.

6.3.3 PERFORMANCE EVALUATION

Accidents which require ECCS operation are the following:

1. Inadvertent opening of a steam generator relief or safety valve (see Section 15.1.4).

2. Loss of reactor coolant from small ruptured pipes or from cracks in large pipes which actuates the ECCS (see Section 15.6.5).

3. Major reactor coolant system pipe ruptures (LOCA) (see Section 15.6.5).

4. Steam system piping failure (see Section 15.1.5).

5. Steam generator tube failure (see Section 15.6.3).

The ECCS is actuated from any of the following:

1. Two out of four low pressurizer pressure signals.

2. Two out of three high-1 containment pressure signals.

3. Two out of three low steam line pressure signals in any one loop.

4. Manual initiation.

6.3.3.1 Inadvertent Opening of a Steam Generator Relief or Safety Valve

The adequacy of the ECCS is demonstrated through compliance with the relevant event acceptance criteria, as described in Section 15.1.4.

6.3.3.2 Loss of Reactor Coolant from Small Ruptured Pipes or from Cracks in Large Pipes Which Actuate the Emergency Core Cooling System

The adequacy of the ECCS is demonstrated through compliance with the relevant event acceptance criteria, as described in Section 15.6.5.

6.3.3.3 Major Reactor Coolant System Pipe Ruptures (Loss of Coolant Accident)

The adequacy of the ECCS is demonstrated through compliance with the relevant event acceptance criteria, as described in Section 15.6.5.

6.3.3.4 Steam System Piping Failure

The adequacy of the ECCS is demonstrated through compliance with the relevant event acceptance criteria, as described in Section 15.1.5.

6.3.3.5 Steam Generator Tube Failure

The adequacy of the ECCS is demonstrated through compliance with the relevant event criteria, as described in Section 15.6.3.

6.3.3.6 Existing Criteria Used to Judge the Adequacy of the ECCS

The relevant acceptance criteria for the each event that requires the operation of the ECCS are described in Chapter 15.

6.3.3.7 Use of Dual Function Components

The ECCS contains components which have no other operating function as well as components which are shared with other systems. Components in each category are as follows:

1. Components of the ECCS which perform no other function are:

   a. One accumulator for each loop which discharges borated water into its respective cold leg of the reactor coolant loop piping.

   b. Two safety injection pumps, which supply borated water for core cooling to the RCS. (May be used during check valve testing also and filling of Safety Injection Accumulators.)

   c. Associated piping, valves and instrumentation.

2. Components which also have a normal operating function are as follows:

   a. The residual heat removal pumps and the residual heat exchangers: These components are normally used during the latter stages of normal reactor cooldown and when the reactor is held at cold shutdown for core decay heat removal. However, during all other plant operating periods, they are aligned to perform the low head injection function. (May also be used during filling of Safety Injection Accumulators.)

   b. The centrifugal charging pumps: These pumps are normally aligned for charging service. As a part of the Chemical and Volume Control System, the normal operation of these pumps is discussed in Chapter 9.

   c. The Refueling Water Storage Tank: This tank is used to fill the refueling cavity for refueling operations. However, during other plant operations it provides an alternate suction to the charging pumps which is automatically aligned on the receipt of a safety injection signal, a low-low level in the VCT, or a boron dilution mitigation signal. During Power Operations (Mode 1), Startup (Mode 2), Hot Standby (Mode 3), and Hot Shutdown (Mode 4), the tank is aligned to provide suction to the safety injection pumps, the containment spray pumps, and the residual heat removal pumps when the latter are not aligned in the RHR cooling mode.

      To prevent the occurrence of water hammer, ECCS piping between containment penetrations and the RWST is kept full of water by gravity in MODES 1 through 4. The highest point in the piping is at El. 825'-6" which is below the minimum RWST level of 850'-5". All lines are equipped with high point vents which ensures complete filling and absence of air pockets.

      Figure 6.3-7 shows the location of the refueling water storage tank vents. Each vent line alone provides the required venting capacity for normal plant operation. In the event of a LOCA, both RWST vents are required to provide the required venting capacity. Tornadoes are not postulated coincident with LOCAs; however, the vents are conservatively designed to break away if struck by a tornado missile to ensure the RWST availability for all design basis events. The vents are located above the tank overflow level, and their blocking by freezing water is not considered feasible. The vents are classified as non-nuclear safety related.

      Blocking of the vents by ice buildups on the tank roof is prevented by the self-draining capability of the roof structure.

An evaluation of all components required for operation of the ECCS demonstrates that either:

1. The component is not shared with other systems, or

2. If the component is shared with other systems, it is either aligned during normal plant operation to perform its accident function or if not aligned to its accident function, two valves in parallel are provided to align the system for injection, and two valves in series are provided to isolate portions of the system not utilized for injection. These valves are automatically actuated by the safety injection signal.

Table 6.3-8 indicates the alignment of components during normal operation, and the realignment required to perform the accident function.

In all cases of component operation, safety injection has the priority usage such that an "S" signal will override all other signals and start or align systems for injection.

6.3.3.8 Limits on System Parameters

The analyses show that the design basis performance characteristic of the ECCS is adequate to meet the requirements for core cooling following a LOCA with the minimum engineered safety feature equipment operating. In order to ensure this capability in the event of the simultaneous failure to operate any single active component, Technical Specifications are established for reactor operation.

Normal operating status of ECCS components is given in Table 6.3-9.

The ECCS components are available whenever the coolant energy is high and the reactor is critical. During low temperature physics tests there is a negligible amount of stored energy in the coolant and low decay heat; therefore, an accident comparable in severity to accidents occurring at operating conditions is not possible and ECCS components are not required.

The principal system parameters and the number of components which may be out of operation in test, quantities and concentrations of coolant available, and allowable time in a degraded status are illustrated in the Technical Specifications. If efforts to repair the faulty component are not successful, the plant is placed into a lower operational status, i.e., hot standby to hot shutdown, hot shutdown to cold shutdown, etc.

6.3.4 TESTS AND INSPECTIONS

6.3.4.1 ECCS Performance Tests

6.3.4.1.1 Preoperational Test Program at Ambient Conditions

Preliminary operational testing of the ECCS can be conducted during the hot functional testing of the RCS following flushing and hydrostatic testing, with the system cold and the reactor vessel head removed. Provision should be made for excess water to drain into the refueling canal. The ECCS must be aligned for normal power operation. Simultaneously, the safety injection block switch is reset and the breakers on the lines supplying offsite power are tripped manually so that operation of the emergency diesels is tested in conjunction with the SIS. This test should provide information including the following facets:

1. Satisfactory safety injection signal generation and transmission.

2. Proper operation of the emergency diesel generators, including sequential load pickup.

3. Valve operating times.

4. Pump starting times.

5. Pump delivery rates at runout conditions (one point on the operating curve).

6.3.4.1.2 Components

1. Pumps

Separate flow tests of the pumps in the ECCS are conducted during the operational startup testing (with the reactor vessel head off) to check capability for sustained operation. The centrifugal charging, safety injection, and residual heat removal pumps will discharge into the reactor vessel through the injection lines, the overflow from the reactor vessel passing into the refueling canal. Each pump will be tested separately with water drawn from the Refueling Water Storage Tank. In the case of the RHR pumps, water may optionally be drawn from the Reactor Coolant System hot legs. Data will be taken to determine pump head and flow at this time. Pumps will then be run on miniflow circuits and data taken to determine a second point on the head flow characteristic curve.

2. Accumulators

Each accumulator is filled with water from the Refueling Water Storage Tank and pressurized with the motor operated valve on the discharge line closed. Then the valve is opened and the accumulator allowed to discharge into the reactor vessel as part of the operational startup testing with the reactor cold and the vessel head off.

Conformance with Regulatory Guide 1.79 is discussed in Appendix 1A(B).

6.3.4.2 Reliability Tests and Inspections

Routine periodic testing of the ECCS components and all necessary support systems at power is planned. Valves which operate after a LOCA are operated through a complete cycle, and pumps are operated individually in this test. If such testing indicates a need for corrective maintenance, the redundancy of equipment in these systems permits such maintenance to be performed without shutting down or reducing load under certain conditions. These conditions include considerations such as the period within which the component should be restored to service and the capability of the remaining equipment to provide the minimum required level of performance during such a period.

The operation of the remote stop valve and the check valve in each accumulator tank discharge line may be tested by opening the remote test line valves just downstream of the stop valve and check valve, respectively. Flow through the test line can be observed on instruments, and the opening and closing of the discharge line stop valve can be sensed on this instrumentation.

The ECCS is designed with the capability to determine leakage from the RCS to the ECCS through any of the series check valves which are located in each accumulator, residual heat removal pump, safety injection pump, and charging pump cold leg or hot leg injection line. Tests are performed to verify that each series check valve can independently sustain a differential

pressure across its disc and also to verify that the valve is in its closed position. The following check valves are provided with leakage detection capability:

8818 A thru D
SI-8819 A thru D
8948 A thru D
8956 A thru D
8949 A thru D
SI-8905 A thru D
SI-8900 A thru D
8841 A and B
8815

Where series pairs of checks valves form the high pressure to low pressure isolation barrier between the RCS and the SIS piping outside the Containment (8818 A thru D, 8819 A thru D, 8948 A thru D & 8956 A thru D), periodic testing of these check valves must be performed to provide assurance that certain postulated failure modes will not result in a loss of coolant from the low pressure system outside Containment with a simultaneous loss of safety injection pumping capacity. The SIS test line subsystem provides the capability for determination of the integrity of the pressure boundary formed by series check valves. As noted above, the tests performed verify that each of the series check valves can independently sustain differential pressure across its disc, and also verify that the valve is in its closed position. The required periodic tests are to be performed after each refueling just prior to plant startup, after the RCS has been pressurized.

Lines in which the series check valves are to be tested include the safety injection pump injection lines, the residual heat removal pump injection lines, and the SIS accumulator discharge lines.

To implement the periodic component testing requirements, Technical Specifications have been established. See the Technical Specifications for the selection of test frequency, acceptability of testing, and measured parameters for the testing described in this Section. During periodic system testing, a visual inspection of pump seals, valve packings, flanged connections, and relief valves is made to detect leakage. Leakage must be within Technical Specification limits for RCS leakage.

Design measures have been taken to assure that the following testing can be performed:

1. Active components may be tested periodically for operability (e.g., pumps, certain valves, etc.).

2. An integrated system actuation test[(a)] can be performed when the plant is cooled down and the RHRS is in operation. The ECCS will be arranged so that no flow will be introduced into the RCS for this test.

3. An initial flow test of the full operational sequence can be performed.

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a. Details of the testing of the sensors and logic circuits associated with the generation of a safety injection signal together with the application of this signal to the operation of each active component are given in Section 7.2.

The design features which assure this test capability are specifically:

1. Power sources are provided to permit individual actuation of each active component of the ECCS.

2. The safety injection pumps can be tested periodically during plant operation using the minimum flow recirculation lines provided.

3. The residual heat removal pumps are used every time the RHRS is put into operation. They can also be tested periodically when the plant is at power using the miniflow recirculation lines.

4. The centrifugal charging pumps are either normally in use for charging service or can be tested periodically.

5. Remote operated valves can be exercised during routine plant maintenance.

6. Level and pressure instrumentation is provided for each accumulator tank, for continuous monitoring of these parameters during plant operation.

7. Flow from each accumulator tank can be directed at any time through a test line to determine check valve leakage and to demonstrate operation of the accumulator motor operated valves.

8. A flow indicator is provided in the safety injection pump header, and in the residual heat removal pump headers. Pressure instrumentation is also provided in these lines.

9. An integrated system test can be performed when the plant is cooled down and the RHRS is in operation. This test does not introduce flow into the RCS but does demonstrate the operation of the valves, pump circuit breakers, and automatic circuitry including diesel starting and the automatic loading of ECCS components of the diesels (by simultaneously simulating a loss of offsite power to the vital electrical buses).

Inservice inspection provides further confirmation that no significant deterioration is occurring in the ECCS fluid boundary. A description of the inservice inspection program is provided in the Unit 1 and Unit 2 Inservice Inspection Program Plans. ECCS components and systems are designed to meet the intent of the ASME Code, Section XI for inservice inspection.

6.3.5 INSTRUMENTATION REQUIREMENTS

Instrumentation and associated analog and logic channels employed for initiation of ECCS operation is discussed in Section 7.3. This section describes the instrumentation employed for monitoring ECCS components during normal plant operation and also ECCS post accident operation. All alarms are annunciated in the Control Room.

6.3.5.1 Temperature Indication

6.3.5.1.1 Boron Injection Tank Temperature

Deleted from the CPNPP design; refer to section 6.3.2.2.2.

6.3.5.1.2 Residual Heat Exchanger Outlet Temperature

The fluid temperature at the outlet of each residual heat exchanger is recorded in the Control Room.

6.3.5.1.3 Boron Injection Surge Tank Temperature

Deleted from the CPNPP design; refer to Section 6.3.2.2.3.

6.3.5.2 Pressure Indication

6.3.5.2.1 Boron Injection Tank Pressure

Deleted from the CPNPP design; refer to Section 6.3.2.2.2

6.3.5.2.2 Safety Injection Pump Discharge Pressure

Safety injection pump discharge pressure is indicated in the Control Room.

6.3.5.2.3 Accumulator Pressure

Duplicate pressure channels are installed on each accumulator. Pressure indication in the Control Room and high and low pressure alarms are provided by each channel.

6.3.5.2.4 Test Line Pressure

A local pressure indicator used to check for proper seating of the accumulator check valves between the injection lines and the RCS is installed on the leakage test line.

6.3.5.2.5 Residual Heat Removal Pump Discharge Pressure

Residual heat removal discharge pressure for each pump is indicated in the Control Room. A high pressure alarm is actuated by each channel.

6.3.5.2.6 Pressure Monitoring

In response to Generic Letter 2008-01 [Ref. 1], pressure transmitters are provided to monitor ECCS piping that may be affected by potential gas sources. Monitoring of ECCS piping while the systems ar in normal stand-by status provided to ensure that the systems are in compliance with regulations and the operating license. The monitoring and TS Surveillance Requirements are designed to ensure that the ECCS systems are water solid, where required, and provide the basis to show compliance with the applicable regulatory requirements including 10 CFR50 Appendix A, General Design Criteria 1, 34, 10 CFR 50.36(c)(3).

Pressure indication is provided within the RHRS Pump Discharge Header, the SI Pump Discharge Header, the SI Hot Leg Injection Headers, the CCP Injection Header to Cold Leg Injection Header, and the SI Test Line Header to monitor ECCS piping pressure while the systems are in normal stand-by status. Pressure indication is retrieved from the Plant Computer System.

6.3.5.3 Flow Indication

6.3.5.3.1 Boric Acid Recirculation Flow

Deleted from the CPNPP design.

6.3.5.3.2 Charging Pump Injection Flow

Injection flow through the reactor cold leg is indicated in the Control Room.

6.3.5.3.3 Safety Injection Pump Header Flow

Flow through the safety injection pump header is indicated in the Control Room.

6.3.5.3.4 Residual Heat Removal Pump Injection Flow

Flow through each residual heat removal injection and recirculation header leading to the reactor cold or hot legs is indicated in the Control Room.

6.3.5.3.5 Test Line Flow

Local indication of the leakage test line flow is provided to check for proper seating of the accumulator check valves between the injection lines and the RCS.

6.3.5.3.6 Residual Heat Removal Return Line Flow

The return flow of reactor coolant from the residual heat removal loop during normal plant cooldown is recorded in the Control Room.

6.3.5.3.7 Safety Injection Pump Minimum Flow

A flow indicator is installed in the safety injection pump minimum flow line.

6.3.5.3.8 Residual Heat Removal Pump Minimum Flow

A flowmeter installed in each residual heat removal pump discharge header provides control for the valve located in the pump minimum flow line.

6.3.5.3.9 Pressure Isolation Valve Leakage Monitoring System

Unit 2 is provided with a leak measurement line from valve 2SI-8975 equipped with flow measurement instruments to measure intersystem leakage through RCS pressure isolation valves into the SI injection header. This alternate relief path may be used to route this leakage to the recycle holdup tank in lieu of via the SI injection header relief valves. The line is designed to limit the SI system loss to less than or equal to 0.2 gpm when the isolation valve is open even in the event of an SSE. When using the line unattended in this mode, this design leakage will also be tracked as part of the leakage limit for primary coolant sources outside the containment structure as discussed in TMI Section III.D.1.1 of the FSAR to ensure the 1 gpm limit is not exceeded in the event of an accident.

6.3.5.4 Level Indication

6.3.5.4.1 Refueling Water Storage Tank Level

Four water level indicator channels, which indicate in the Control Room, are provided for the Refueling Water Storage Tank. Each channel is provided with a high, low, low-low and empty level alarm.

The high level alarm is provided to protect against possible overflow of the Refueling Water Storage Tank.

The low level alarm is provided to assure that a sufficient volume (473,731 gallons) of water is always available in the Refueling Water Storage Tank (RWST) in conformance with the Technical Specifications. Receipt of a low level alarm, concurrent with receipt of an "S" signal, also alerts the operator that: 1) ECCS cold leg injection is in progress, and 2) that manual action will be required to effect ECCS switchover to the recirculation mode when the RWST low-low level alarm is received.

The low-low level alarm automatically initiates ECCS switchover (by opening the recirculation sump isolation valves). Concurrently, the RWST low-low level alarm alerts the operator of the automatic initiation of ECCS switchover and that manual actions (as delineated in Table 6.3-7) must be performed to realign the ECCS from the injection mode to the recirculation mode following an accident.

The empty alarm indicates that the usable volume of the Refueling Water Storage Tank is nearing depletion. Upon receipt of the empty alarm, the operator stops any ECCS pump still taking suction from the RWST. After performing any pump protection required for the ECCS pumps, the operator would complete any required actions to isolate the containment spray pumps from the RWST or ensure pump protection from loss of suction. The empty alarm ensures sufficient volume is available to stop any pump still taking suction from the RWST. Each channel also provides level indication in the Control Room.

6.3.5.4.2 Accumulator Water Level

Duplicate water level channels are provided for each accumulator. Both channels provide indication in the Control Room and actuate high and low water level alarms.

6.3.5.4.3 Boron Injection Surge Tank Level

Deleted from the CPNPP design.

6.3.5.5 Valve Position Indication

Valve positions which are indicated on the control board are done so by a "normal off" system; i.e., should the valve not be in its proper position, a bright white light will be lit and thus give a highly visible indication to the operator.

The accumulator motor operated valves are provided with red (open) and green (closed) position indicating lights located at the control switch for each valve. These lights are powered by valve control power and actuated by valve motor operator limit switches. These position indicators

function when control power is removed by a key lock switch at the Main Control Board in accordance with BTP ICSB-18. However, these position indicators do not function when power is removed at the Motor Control Center.

A monitor light that is on when the valve is not fully open is provided in an array of monitor lights that are all off when their respective valves are in proper position enabling safeguards operation. This light is energized from a separate monitor light supply and actuated by a valve motor operated limit switch.

To meet the intent of BTP ICSB-18, an alarm annunciator point is activated by both a valve motor operator limit switch and by a valve position limit switch activated by stem travel whenever an accumulator valve is not fully open for any reason with the system at pressure (the pressure at which the safety injection block is unblocked is approximately 1900 psig). A separate annunciator point is used for each accumulator valve. This alarm will be recycled at approximately 1 hour intervals to remind the operator of the improper valve lineup.

All ECCS motor operated and air operated valves have position indication in the control room by monitor lights and/or red/green position indication lights (see Table 6.3-3). The position in which the valves are located (open or closed) and locked into position are those which ensure ECCS operability.

The position of manual valves 1SI-047 and 1-8717 is indicated and alarmed by means of the SSII (Safety System Inoperable Indication - see FSAR Section 7.1.2.6). 1SI-047 is on the line from the RWST to the ECCS pump suction. If 1SI-047 is not open, an SSII module light will flash and a horn will sound. 1-8717 is on the return line from the RHRS pump discharge to the RWST. If 1-8717 is not closed, an SSII module light will flash and a horn will sound.

REFERENCES

1. NRC Generic Letter 2008-01, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems”, dated January 11, 2008.

TABLE 6.3-1
EMERGENCY CORE COOLING SYSTEM COMPONENT PARAMETERS

(Sheet 1 of 3)

Component	Parameter
Accumulators	
Number	4
Design pressure (psig)	700
Design temperature (°F)	300
Operating temperature (°F)	70-150
Maximum operating pressure (psig)	693
Minimum operating pressure (psig)	603
Total volume (ft^3)	1350 each
Minimum water volume (gal)	6119 each
Volume nitrogen gas (ft^3)	500
Boric acid concentration, nominal (ppm)	2400
Boric acid concentration, minimum (ppm)	2300
Relief valve setpoint (psig)	700
Centrifugal Charging Pumps	
Number	2
Design pressure (psig)	2800
Design temperature (°F)	300
Design flow rate[(a)] (gpm)	150
Design head (ft)	5800
Maximum flow rate (gpm)	550
Head at maximum flow rate (ft)	1400
Discharge head at shutoff (ft)	6000
Motor rating[(b)] (php)	600

TABLE 6.3-1
EMERGENCY CORE COOLING SYSTEM COMPONENT PARAMETERS

(Sheet 2 of 3)

Component	Parameter
Required NPSH (ECCS) maximum flow rate (ft)	22
Available NPSH (ft)	26.7
Safety Injection Pumps	
Number	2
Design pressure (psig)	1860
Design temperature (°F)	200
Design flow rate (gpm)	425
Design head (ft)	2680
Maximum flow rate (gpm)	650
Head at maximum flow rate (ft)	1650
Discharge head (ft)	3600
Motor rating[(b)] (bhp)	450
Required NPSH (ft)	25
Available NPSH (ft)	>34
Residual Heat Removal Pumps	
(See Section 5.4.7 for design parameters)	
Residual Heat Exchangers	
(See Section 5.4.7 for design parameters)	
Valves	

Motor operated valves	Valve Size (in.)	Max.open.or closing time
8814A & B	1.5	10 sec.

TABLE 6.3-1
EMERGENCY CORE COOLING SYSTEM COMPONENT PARAMETERS

(Sheet 3 of 3)

Component		Parameter
8110, 8111, 8813	2	10 sec.
8511 A & B, 8512 A & B	2	10 sec.
FCV-610, FCV-611	3	15 sec.
8105, 8106	3	10 sec.
8801 A & B	4	10 sec.
8802 A & B, 8835	4	15 sec.
LCV-112 B & C	4	10 sec.
8821 A & B	4	15 sec.
8807 A & B, 8923 A & B, 8924	6	15 sec.
8804 A & B, 8806, LCV-112 D & E	8	15 sec.
8716 A & B	10	15 sec.
8809 A & B, 8840	10	20 sec.
8811 A & B, 8812 A & B	14	20 sec.
8701 A & B, 8702 A & B	12	120 sec.
8808 A - D	10	20 sec.

a) Includes miniflow.

b) 1.15 service factor not included.

TABLE 6.3-2
EMERGENCY CORE COOLING SYSTEM RELIEF VALVE DATA

Description	Fluid Discharge	Fluid Inlet Temperature (Normal)	Set Pressure (Psig)	Back Pressure Constant	Psig Buildup	Capacity
Nitrogen supply to accumulators	Nitrogen	120	750 Tag # (1-8857) 750 Tag # (2-8857)	0	0	1500 scfm
Safety injection pump discharge	Water	100	1860	3	50	20 gpm
Residual heat removal pump safety injection line	Water	120	600	3	50	20 gpm
Safety injection pumps suction header	Water	120	220	3	50	20 gpm
Accumulator to Containment	Water or nitrogen gas	120	700	0	0	1500 scfm

TABLE 6.3-3
MOTOR OPERATED ISOLATION VALVES IN THE EMERGENCY CORE COOLING SYSTEM

(Sheet 1 of 3)

Location Indication	Valve Identification	Interlocks	Automatic Features	Position Indication	Alarms	Monitor Light Box
Accumulator	8808 A,B,C,D	Power lockout Cannot be closed with "S" signal or when manually locked out	Open on "S" signal, or RCS pressure greater than unblock	MCB	Yes-out of position	Yes
Safety injection pump suction from RWST	8806	Power lockout	None	MCB	Yes-out of position	Yes
RHR suction from RWST	8812 A&B	Cannot be opened unless sump valve closed	None	MCB	Yes-out of position	Yes
Safety injection pump suction isolation valves	8923 A&B	None	None	MCB	No	Yes
RHR discharge to safety injection/charging pump	8804 A&B	Cannot be opened unless safety injection pump miniflow isolated and RHR suction from RCS isolated	None	MCB	No	Yes
Safety injection hot leg injection	8802 A&B	Power lockout	None	MCB	No	Yes
RHR hot leg injection	8840	Power lockout	None	MCB	No	Yes
Containment sump isolation valve	8811 A & B	Cannot be opened in normal operation unless RHR suction valves from RWST and one of two RCS suction series valves are closed.	Opens on RWST Lo-Lo with "S" signal	MCB	No	Yes
CVCS suction from RWST	LCV-112 D&E	None	Opens on "S" signal, or VCT Lo-Lo level	MCB	No	Yes

TABLE 6.3-3
MOTOR OPERATED ISOLATION VALVES IN THE EMERGENCY CORE COOLING SYSTEM

(Sheet 2 of 3)

Location Indication	Valve Identification	Interlocks	Automatic Features	Position Indication	Alarms	Monitor Light Box
CVCS normal suction	LCV-112 B& C	None	With CVCS suction from RWST open, closes on "S" signal, or VCT Lo-Lo level	MCB	No	Yes
Safety injection pump to cold leg	8835	Power Lockout	None	MCB	No	Yes
CVCS normal discharge	8105 8106	None	Closes on "S" signal	MCB	No	Yes
High head safety injection isolation valves	8801 A&B	None	Opens on "S" Signal	MCB	No	Yes
Charging and safety injection pump header from RHR	8807 A&B 8924	None None	None None	MCB MCB	No None	Yes Yes
RHR to RCS cold legs	8809 A&B	Power lockout	None	MCB	No	Yes
Safety injection pump miniflow	8813	Power lockout. Cannot be opened unless RHR discharge to SI/CHG pump valves closed.	None	MCB	No	Yes
	8814 A&B	Cannot be opened unless RHR discharge to SI/CHG pump valves closed.				
RHR cross connect	8716 A&B	None	None	MCB	No	Yes
Safety injection pump cross connect	8821 A&B	None	None	MCB	No	Yes
Charging pump miniflow isolation valves	8110 8111	None	Closes on "S" signal	MCB	No	Yes

TABLE 6.3-3
MOTOR OPERATED ISOLATION VALVES IN THE EMERGENCY CORE COOLING SYSTEM

(Sheet 3 of 3)

Location Indication	Valve Identification	Interlocks	Automatic Features	Position Indication	Alarms	Monitor Light Box
RHR hot leg suction isolation valves	8701 A, B 8702 A, B	Cannot be opened unless there is no RCS High-1 pressure and Containment sump isolation valve, RHR suction from RWST valve and RHR discharge to safety injection/charging pump suction valves are closed.		MCB	Yes-out of position	No
Charging pump alternate miniflow isolation valves	8511 A, B	Cannot be opened manually from MCB unless the CVCS suction from the VCT valve is closed and the RHR discharge to safety injection/charging pump suction valves are closed.	Opens on "S" signal	MCB	No	Yes
Charging pump alternate miniflow isolation valve	8512 A, B	Cannot be opened unless the RHR discharge to safety injection/charging pump suction valves are closed.	None	MCB	No	Yes
RHR pump recirculation	FCV 610, 611	None	Opens when flow from the RHR pump is low. Closes when flow from the RHR pump is High 10 sec after the pump has started.	MCB	No	No

Power lockout - Control board control power cut-off switch to prevent spurious movement. Valve remains "as is" when control power is cut-off.

Note 1 - Monitor and hand switch

MCB-Main Control Board

TABLE 6.3-4
MATERIALS EMPLOYED FOR EMERGENCY CORE COOLING SYSTEM COMPONENTS

(Sheet 1 of 2)

Component	Material
Accumulators	Carbon steel, clad with austenitic stainless steel
Pumps	
Centrifugal charging	Austenitic stainless steel
Safety injection	Austenitic stainless steel
Residual heat removal	Austenitic stainless steel
Residual heat exchangers	
Shell	Carbon steel
Shell end cap	Carbon steel
Tubes	Austenitic stainless steel
Channel	Austenitic stainless steel
Channel cover	Austenitic stainless steel
Tubesheet	Austenitic stainless steel
Valves	
Motor operated valves containing radioactive fluids	
Pressure containing parts	Austenitic stainless steel or equivalent
Body-to-bonnet	ASME SA-453 grade 660 (NUT-ASME 193, B6, Type 410) (All other parts - SA-194)
Seating surfaces	Stellite No. 6 or other material suitable for the application
Stems	Austenitic stainless steel or 17-4 pH stainless

TABLE 6.3-4
MATERIALS EMPLOYED FOR EMERGENCY CORE COOLING SYSTEM COMPONENTS

(Sheet 2 of 2)

Component	Material
Motor operated valves containing nonradioactive, boron-free fluids	
Body, bonnet and flange	Carbon steel
Stems	Corrosion resistance steel
Diaphragm valves	Austenitic stainless steel
Accumulator check valves	
Parts contacting borated water	Austenitic stainless steel
Relief valves	
Stainless steel bodies	Stainless steel
Carbon steel bodies	Carbon steel
All nozzles, discs, spindles and guides	Austenitic stainless steel
Bonnets for stainless steel valves without a balancing bellows	Stainless steel or plated carbon steel
All other bonnets	Carbon steel
Piping	
All piping in contact with borated water	Austenitic stainless steel

TABLE 6.3-5
SINGLE ACTIVE FAILURE ANALYSIS FOR EMERGENCY CORE COOLING SYSTEM COMPONENTS

(Sheet 1 of 3)

Component	Malfunction	Comments
Short Term Phase		
1. Pumps		
a. Centrifugal charging	Fails to start	Two provided, evaluation based on operation of one.
b. Safety injection	Fails to start	Two provided, evaluation based on operation of one.
c. Residual heat removal	Fails to start	Two provided, evaluation based on operation of one.
2. Automatically operated valves		
a. High head safety injection isolation valve	Fails to open	Two parallel lines; one valve in either line required to open.
b. Residual heat removal pumps suction line to containment sump	Fails to open	Two parallel lines; only one valve in either line required to open.
c. Centrigugal charging pumps		
1) Suction line from refueling water storage tank	Fails to open	Two parallel valves; only one valve required to open.

TABLE 6.3-5
SINGLE ACTIVE FAILURE ANALYSIS FOR EMERGENCY CORE COOLING SYSTEM COMPONENTS

(Sheet 2 of 3)

Component			Malfunction	Comments
	2)	Discharge line to the normal charging pathvalve	Fails to close	Two valves in series; only one required to close.
	3)	Miniflow bypass line	Fails to close	Two valves in series; only one valve required to close.
	4)	Suction from volume control tank	Fails to close	Two valves in series; only one valve required to close.
	5)	Suction line high point vent	Fails to close	Two valves in series; only one valve required to close.
Long Term Phase				
1.	Valves operated manually from the control room			
	a.	Residual heat removal pumps suction line from refueling water storage tank	Fails to close	Check valve in series with one gate valve; operation of only one valve required.
	b.	Safety injection pump suction line from refueling water storage tank	Fails to close	Check valve in series with one gate valve; operation of only one valve required.
	c.	Centrifugal charging pump suction line from refueling water storage tank	Fails to close	Check valve in series with two parallel gate valves; operation of either check valve or both of the gate valves required.

TABLE 6.3-5
SINGLE ACTIVE FAILURE ANALYSIS FOR EMERGENCY CORE COOLING SYSTEM COMPONENTS

(Sheet 3 of 3)

Component		Malfunction	Comments
d.	High head pump suction line at discharge of residual heat exchanger	Fails to open	Separate and independent high head injection paths to safety injection pumps and charging pumps taken suction from discharge of residual heat exchangers; operation of only one valve required.
e	Residual heat removal cross connect line	Fails to close	Two valves in series; operation of one required.
f.	Safety injection pump miniflow lines	Fails to close	Two parallel valves provided in series with a third; operation of either both parallel valves or series valve required.
g.	Safety injection/charging cross connect line in suction header	Fails to open	Two parallel valves provided; operation of either one required.
h.	Safety injection/residual heat removal hot leg isolation valves	Fails to open	Three flow paths available; adequate flow to core is assured by any two.
i.	Safety injection/residual heat removal cold leg isolation valves	Fails to close	Redundant valves provided with suitable arrangements to preclude pump runout.

TABLE 6.3-6
EMERGENCY CORE COOLING SYSTEM RECIRCULATION PIPING PASSIVE FAILURE ANALYSIS LONG TERM PHASE

Flow Path	Indication of Loss of Flow Path	Alternate Flow Path
Low Head Recirculation		
From containment sump to the low head injection header via the residual heat removal pumps and the residual heat exchangers	Accumulation of water in a residual heat removal pump compartment or the Safeguards Building sump	Via the independent, identical low head flow path utilizing the second residual heat exchanger and residual heat removal pump
High Head Recirculation		
From containment sump to the high head injection header via the residual heat removal pump, residual heat exchanger and high head injection pumps	Accumulation of water in a residual heat removal pump compartment or the Safeguards Building sump or safety injection or charging pump compartments	From containment sump to the high head injection headers via alternate residual heat removal pump, residual heat exchanger, safety injection or charging pump

TABLE 6.3-7
SEQUENCE OF SWITCHOVER OPERATIONS (BASED ON NO SINGLE FAILURES)

(Sheet 1 of 4)

SWITCHOVER FROM INJECTION TO COLD LEG RECIRCULATION

The following manual operator actions are required to perform the switchover operation from the ECCS cold leg injection mode to the cold leg recirculation mode. Following event initiation and upon receipt of the RWST low level alarm, the operator is in the process of anticipating the RWST low-low level switchover initiation alarm. The operator monitors the RWST level and containment recirculation sump in anticipation of switchover. During the cold leg injection mode and prior to the receipt of the RWST Low-Low level alarm, the operator is to:

(a) verify that all ECCS pumps are operating and are delivering flow to the RCS cold legs, and

(b) monitor the RWST and the containment recirculation sump levels.

Upon receipt of the RWST low-low level signal, the operator is required to reset SI and to verify that the component cooling water isolation valves for the heat exchangers are open. The emergency procedure includes cautions and notes, as required. The operator is then required to verify the sump isolation valves are open and to perform the manual actions listed below in an orderly and timely manner, and in the proper sequence. Manual actions 1 thru 6 function to align the suction of the residual heat removal pumps to the containment sump and to align the suction of the charging & safety injection pumps to the discharge of the residual heat removal pumps, thereby assuring an available suction source for all ECCS pumps. The remaining operator actions serve only to provide redundant isolation of the RWST from the recirculation fluid.

SWITCHOVER STEPS (Note 1)

The RWST low-low level signal automatically initiates opening of the containment sump isolation valves (8811 A&B). Upon receipt of the RWST low-low level signal the operator is to immediately enter the emergency procedure for transfer to cold leg recirc and perform the following actions:

STEP 1: When each sump isolation valve (8811 A&B) has reached the full open position, take immediate action to close the corresponding RWST to residual heat removal pump suction isolation valve (8812 A&B).

STEP 2: Close the three Safety Injection Pump miniflow valves (8813, 8814A, and 8814B).

STEP 3: Close the two valves in the crossover line downstream of the residual heat removal heat exchangers (8716 A&B).

STEP 4: Close the CCP miniflow to RWST valves (8511A, 8511B, 8512A, 8512B).

TABLE 6.3-7
SEQUENCE OF SWITCHOVER OPERATIONS (BASED ON NO SINGLE FAILURES)

(Sheet 2 of 4)

STEP 5: Open the two parallel valves in the common suction lines between the charging pump suction and the safety injection pump suction (8807 A&B).

STEP 6: Open each valve from each residual heat removal pump discharge line to the charging pump suction and to the safety injection pump suction (8804 A&B respectively).

All ECCS pumps are now aligned with suction flow from the containment sump. See Table 6.3-11 for additional information on these switchover steps.

STEP 7: Verify proper operation and alignment of all ECCS components. Complete the following manual actions to provide redundant isolation of the RWST from the recirculation fluid.

STEP 8: Close the two parallel valves in the line from the RWST to the charging pump suction (LCV-112 D&E).

STEP 9: Restore power to and close the valve in the common line from the RWST to both safety injection pumps (8806).

The ECCS is now aligned for cold leg recirculation as follows:

a. Both residual heat removal pumps are delivering from the containment sump directly to the RCS cold legs and are also delivering to the suction of the safety injection and charging pumps.

b. Both safety injection and charging pumps are delivering to the RCS cold legs.

Notes (1) The operator actions for switchover from injection to cold leg recirculation are not to be interrupted until all of the steps in the switchover are completed; however, if the RWST EMPTY level alarm is received any time during the switchover, immediately stop any ECCS pumps still taking suction from the RWST, then complete the switchover and restart any pump which was stopped, starting with the residual heat removal pump.

The RWST level indication then informs the operator that sufficient water has been injected into containment and to initiate switchover of the containment spray system.

STEP 10: Switchover all four (4) containment spray pumps.

TABLE 6.3-7
SEQUENCE OF SWITCHOVER OPERATIONS (BASED ON NO SINGLE FAILURES)

(Sheet 3 of 4)

SWITCHOVER FROM COLD LEG-RECIRCULATION TO HOT LEG RECIRCULATION

At approximately 3 hours after the accident, hot leg recirculation shall be initiated. The following manual operator actions are required to perform the switchover operation from the cold leg recirculation mode to the hot leg recirculation mode. These steps are the general steps required to complete the switchover for both trains of ECCS. Plant procedures may direct completion of steps by individual train as necessary based on component availability.)

SWITCHOVER STEPS

STEP 1: Close the residual heat removal pump discharge cold leg header isolation valves (8809 A/B).

STEP 2: Open the residual heat removal pump discharge crossover isolation valves (8716 A/B).

(a)STEP 3: Open the residual heat removal pump discharge hot leg header isolation valve (8840).

STEP 4: Stop safety injection pump No. 1.

STEP 5: Close the corresponding safety injection pump discharge crossover header isolation valve (8821A).

STEP 6: Open the corresponding safety injection pump discharge hot leg header isolation valve (8802A).

(a)STEP 7: Restart safety injection pump No. 1.

STEP 8: Stop safety injection pump No. 2.

STEP 9: Close the corresponding safety injection pump discharge crossover isolation valve (8821B).

STEP 10: Open the corresponding safety injection pump discharge hot leg header isolation valve (8802B).

(a)STEP 11: Restart safety injection pump No. 2.

STEP 12: Close the safety injection pump discharge cold leg header isolation valve (8835).

STEP 13: Open Valve 8821A or 8821B. No preference, however, only one valve may be opened.

TABLE 6.3-7
SEQUENCE OF SWITCHOVER OPERATIONS (BASED ON NO SINGLE FAILURES)

(Sheet 4 of 4)

The ECCS is now aligned for hot leg recirculation as follows:

a. Both residual heat removal pumps are delivering from the containment sump directly to the RCS hot legs and are also delivering to the suction of the safety injection and charging pumps.

b. Both safety injection pumps are delivering to the RCS hot legs. Hot leg flow will dilute the reactor vessel boron concentration by passing relatively dilute boron solution from the hot leg through the vessel to the cold leg break location.

c. Both charging pumps are delivering to the RCS cold legs. High head charging flow will continue to be provided to the RCS cold legs to preclude boron concentration buildup in the vessel for breaks in the hot leg.

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a) Note:

If the alignment of a residual heat removal or safety injection pump for hot leg recirculation is not successful, the affected pump is returned to delivering cold leg recirculation flow, plant staff is consulted, and applicable steps not yet performed are taken to align remaining pump(s) for hot leg recirculation.

TABLE 6.3-8
EMERGENCY CORE COOLING SYSTEM SHARED FUNCTIONS EVALUATION

Component	Normal Operating Arrangement	Accident Arrangement
Refueling water storage tank	Lined up to suction of centrifugal charging, safety injection, residual heat removal, and containment spray pumps	Lined up to section of centrifugal charging, safety injection, residual heat removal, and containment spray pumps
Centrifugal charging pumps	Lined up for charging service	Lined up to cold leg injection header. Valves for realignment meet single failure criteria
Residual heat removal pumps	Lined up to cold legs of reactor coolant piping	Lined up to cold legs of reactor coolant piping
Residual heat removal (RHR) heat exchangers	Lined up to cold legs of reactor coolant piping	Lined up to cold legs of reactor coolant piping

TABLE 6.3-9
NORMAL OPERATING STATUS OF EMERGENCY CORE COOLING SYSTEM
COMPONENTS FOR CORE COOLING

Number of safety injection pumps operable	2
Number of charging pumps operable	2
Number of residual heat removal pumps operable	2
Number of residual heat exchangers operable	2
Refueling water storage tank required water volume (gal) minimum	473,731
Boron concentration in refueling water storage tanks, minimum (ppm)	2,400
Boron concentration in accumulator, minimum (ppm)	2,300
Number of accumulators	4
Minimum accumulator pressure (psig)	603
Minimum accumulator water volume (gal)	6119
System valves, interlocks, and piping required for the above components which are operable	All

TABLE 6.3-10
FAILURE MODE AND EFFECTS ANALYSIS – EMERGENCY CORE COOLING SYSTEM – ACTIVE COMPONENTS

(Sheet 1 of 13)

Component	Failure Mode	ECCS Operation Phase	[(a)]Effect on System Operation	Failure Detection Method	Remarks
1. Motor operated gate valve 1-LCV-112B (1-LCV-112C analogous)	Fails to close on demand	Injection - cold legs of RC loops	Failure reduces redundancy of providing VCT discharge isolation. No effect on safety for system operation; valve (1-LCV-112C) provides backup tank discharge isolation.	Valve position indication (open to closed position change) at CB. Valve close position monitor light for group monitoring of components at CB. Periodic tests and inspection in compliance with surveillance requirements of plant's technical specification.	Valve is electrically interlocked to close on actuation by a SI "S" signal or a "low-low level" VCT signal providing isolation valve 1-LCV-112D (1-LCV-112E analogs.) is at a full open position.
2. Motor operated gate valve 1-LCV-112D (1-LCV-112E analogous)	Fails to open on demand	Injection - cold legs of RC loops	Failure reduces redundancy of providing fluid flow from RWST to section of HHSI/CH pumps. No effect on safety for system operation. Alternate isolation valve (1-LCV-112E) opens to provide backup flow path to suction of HHSI/CH pumps.	Same methods of detection as that stated for item #1 except open position monitor light for group monitoring of components and closed to open position change indication at CB.	Valve is electrically interlocked to open upon actuation by a SI "S" signal, or by a "Low-low level" VCT signal.
3. Centrifugal charging pump #1, 1-APCH (pump #2 analogous)	Fails to deliver working fluid.	Injection and recirculation cold legs of RC loops.	Failure reduces redundancy of providing emergency coolant to the RCS at prevailing incident RCS pressure. Fluid flow from HHSI/CH pump #1 w/be lost. Minimum flow requirements at prevailing high RCS pressures will be met by HHSI/CH pump #2 delivery via RCS cold legs.	HHSI/CH pump discharge header flow (FI-917) at CB. Open pump switch gear circuit breaker indication on CB. Circuit breaker close position monitor light for group monitoring of components at CB. Common breaker trip alarm at CB. Periodic tests in compliance with surveillance requirements of plant's technical specification.	One HHSI/CH pump is used for normal charging of RCS during plant operation. Pump circuit breaker aligned to close on actuation by a SI "S" signal.

TABLE 6.3-10
FAILURE MODE AND EFFECTS ANALYSIS – EMERGENCY CORE COOLING SYSTEM – ACTIVE COMPONENTS

(Sheet 2 of 13)

Component	Failure Mode	ECCS Operation Phase	[a]Effect on System Operation	Failure Detection Method	Remarks
4. Motor operated globe valve 1-8110 (1-8111 analogous)	Fails to close on demand.	Injection - cold legs of RC loops.	Failure reduces redundancy of providing isolation of HHSI/CH pump miniflow line. No effect on safety for system operation. Alternate isolation valve (1-8111) in miniflow line provides backup isolation.	Same method of detection at that stated for item #1. In addition, close position alarm for group monitoring of components at CB.	Valve aligned to close upon actuation by a SI “S” signal.
5. Motor operated globe valve 1-8105 (1-8106 analogous)	Fails to close on demand.	Injection - cold legs of RC loops.	Failure reduces redundancy of providing isolation of HHSI/CH pump discharge to normal charging line of CVCS. No effect on safety for system operation. Alternate isolation valve (1-8106) provides backup normal CVCS charging line isolation.	Same method of detection as that stated for item #1.	Valve aligned to close upon actuation by a SI "S" signal.
6. Motor operated gate valve 1-8801A (1-8801B analogous)	Fails to open on demand.	Injection - cold legs of RC loops.	Failure reduces redundancy of fluid flow paths from HHSI/CH pumps to the RCS. No effect on safety for system operation. Alternate isolation valve (1-8801B) opens to provide backup flow path from HHSI/CH pumps to the RCS.	Same method of detection as that stated for item #2. In addition, open position alarm for group monitoring of components at CB.	Valve aligned to open upon actuation by a SI "S" signal.

TABLE 6.3-10
FAILURE MODE AND EFFECTS ANALYSIS – EMERGENCY CORE COOLING SYSTEM – ACTIVE COMPONENTS

(Sheet 3 of 13)

Component	Failure Mode	ECCS Operation Phase	[(a)]Effect on System Operation	Failure Detection Method	Remarks
7. Motor operated globe valve 1-FCV-610 (1-FCV-611 analogous)	a. Fails to close on demand.	Injection - cold legs of RC loops.	a. Failure reduces working fluid delivered to RCS from RHR pump #1. Minimum flow requirements for LHSI will be met by LHSI/ RHR pump #2 delivering working fluid to RCS.	a. Valve position indication (open to closed position change) at CB. RHR pump return line to cold legs flow indication (FI-618) at CB. Periodic test and inspection in compliance with surveillance requirements of plant's technical specification.	Valve is regulated by signal from flow transmitter located in pump discharge header. The control valve opens when the RHR pump discharge flow is less than 500 gpm and closes when the flow exceeds 1000 gpm.
	b. Fails closed.	Injection - cold legs of RC loops.	b. Failure results in an insufficient fluid flow through LHSI/RHR pump #1 for a small LOCA or steam line break resulting in possible pump damage. If pump becomes inoperative minimum flow requirements for LHSI will be met by LHSI/RHR pump #2 delivering working fluid to RCS.	b. Same as that stated above for failure mode "fails open" except closed to open position change indication at CB.	

TABLE 6.3-10
FAILURE MODE AND EFFECTS ANALYSIS – EMERGENCY CORE COOLING SYSTEM – ACTIVE COMPONENTS

(Sheet 4 of 13)

Component	Failure Mode	ECCS Operation Phase	[(a)]Effect on System Operation	Failure Detection Method	Remarks
8. Residual heat removal pump #1, 1ARPH (Pump #2 analogous)	Fails to deliver working fluid.	Injection - cold legs of RC loops.	Failure reduces redundancy of providing emergency coolant to the RCS from the RWST at low RCS pressure (195 psig). Fluid flow from LHSI/RHR #1 will be lost. Minimum flow requirements for LHSI will be met by LHSI/RHR pump #2 delivering working fluid.	RHR pump return line to cold legs flow indication (FI-618) and low flow alarm at MCB. RHR pump discharge pressure (PI-614) at CB. Open pump switchgear circuit breaker indication at CB. Circuit breaker close position monitor light for group monitoring of components at CB. Common breaker trip alarm at CB. Periodic tests in compliance with surveillance requirements of plant's technical specification.	The RHR pump is sized to deliver reactor coolant through the RHR heat exchanger to meet plant cooldown requirements & is used during plant cooldown & startup operations. The pump circuit brkr. is aligned to close on actuation by a SI "S" signal.
9. Safety injection pump #1, 1APSI (Pump #2 analogous)	Fails to deliver working fluid.	Injection - cold legs of RC loops.	Failure reduces redundancy of providing emergency coolant to the RCS from the RWST at high RCS pressure(1520 psi). Fluid flow from HHSI/SI pump #1 will be lost. Minimum flow requirements for HHSI will be met by HHSI/SI pump #2 delivering working fluid.	SI pumps discharge pressure (PI-919) at CB. SI pump discharge flow (FI-918) at CB. Open pump switchgear circuit breaker indication at CB. Circuit breaker close position monitor light for group monitoring of components at CB. Common breaker trip alarm at CB. Periodic tests in compliance with surveillance requirements of plant's technical specification.	Pump circuit breaker aligned to close on actuation by a SI "S" signal.

TABLE 6.3-10
FAILURE MODE AND EFFECTS ANALYSIS – EMERGENCY CORE COOLING SYSTEM – ACTIVE COMPONENTS

(Sheet 5 of 13)

Component	Failure Mode	ECCS Operation Phase	[a]Effect on System Operation	Failure Detection Method	Remarks
10. Motor operated gate valve 1-8811A (1-8811B analogous)	Fails to open on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing fluid from the Containment Sump to the RCS during recirculation. LHSI/RHR pump #1 will not provide recirculation flow. Minimum LHSI flow requirements will be met through opening of isolation valve 1-8811B and recirculation of fluid by LHSI/RHR pump #2.	Same method of detection as that stated for item #7. In addition failure may be detected through monitoring of RHR pump return line to cold legs flow indication (FI-618) and RHR pump discharge pressure (PI-614) at CB.	Valve is actuated to open by SI "S" signal in coincidence with two-out-of-four "Low-Low Level" RWST signals. Valve is electrically interlocked from manually being opened by isolation valves 1-8812A, 1-8701A, & 1-8702A.
11. Motor operated gate valve 1-8812A (1-8812B analogous)	Fails to close on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing flow isolation of Containment Sump from RWST. No effect on safety for system operation. Alternate check isolation valve (1-8958A) provides backup isolation.	Same method of detection as that stated for item #4.	Valve is electrically interlocked with isolation valve 1-8811A & may not be opened unless valve 1-8811A is closed.
12. Motor operated gate valve 1-8716A (1-8716B analogous)	Fails to close on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing LHSI/RHR pump train separation for recirculation of fluid to cold legs of RCS. No effect on safety for system operation. Alternate isolation valve (1-8716B) provides backup isolation for LHSI/ RHR pump train separation.	Same method of detection as that stated for item #4.	

TABLE 6.3-10
FAILURE MODE AND EFFECTS ANALYSIS – EMERGENCY CORE COOLING SYSTEM – ACTIVE COMPONENTS

(Sheet 6 of 13)

Component	Failure Mode	ECCS Operation Phase	[a]Effect on System Operation	Failure Detection Method	Remarks
13. Motor operated globe valve 1-8813	Fails to close on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing isolation of HHSI/SI pump's miniflow line isolation from RWST. No effect on safety for system operation. Alternate isolation valve (1-8814A and 1-8814B) in each pump's miniflow line provide back up isolation.	Same method of detection as that stated for time #4.	Valve is electrically interlocked with isolation valves 1-8804A & 1-8804B & may not be opened unless these valves are closed.
14. Motor operated globe valve 1-8814A (1-8814B analogous)	Fails to close on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing isolation of HHSI/SI pump #1 miniflow isolation from RWST. No effect on safety for system operation. Alternate isolation valve (1-8813) in main miniflow line provides backup isolation.	Same method of detection as that stated for item #4.	Same remark as that stated for item #16.
15. Motor operated gate valve 1-8804A.	Fails to open on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing NPSH to suction of HHSI/CH pumps from LHSI/RHR pumps. No effect on safety for system operation Minimum NPSH to HHSI/CH pump suction will be met by flow from LHSI/RHR pump #2 via cross-tie line and opening of isolation valve 1-8807A or 1-8807B and isolation valve 1-8804B.	Same method of detection as that stated for item #7.	Valve is electrically interlocked with isolation valves 1-8814A, 1-8814B, 1-8813, 1-8701A, 1-8702A, 1-8511A, 1-8511B, 1-8512A and 1-8512B. Valve cannot be opened unless 1-8813 or 1-8814A&B are closed, 1-8701A or 1-8702A is closed, 1-8511A or1-8512B is closed and 1-8511B or 1-8512A is closed.

TABLE 6.3-10
FAILURE MODE AND EFFECTS ANALYSIS – EMERGENCY CORE COOLING SYSTEM – ACTIVE COMPONENTS

(Sheet 7 of 13)

Component	Failure Mode	ECCS Operation Phase	[(a)]Effect on System Operation	Failure Detection Method	Remarks
16. Motor operated gate valve 1-8804B	Fails to open on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing NPSH to suction of HHSI/SI pumps from LHSI/RHR pumps. No effect on safety for sytem operation. Minimum NPSH to HHSI/SI pump suction will be met by flow from LHSI/RHR pump #1 via cross-tie line and opening of isolation valve 1-8807A or 1-8807B and isolation valve 1-8804A.	Same method of detection as that stated for item #7.	Same remark as that stated for item #15 except interlocked with valves 1-8701B and 1-8702B.
17. Motor operated gate valve 1-8807-A (1-8807B analogous)	Fails to open on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing fluid flow through cross-tie between suction of HHSI/CH pumps and HHSI/IS pumps. No effect on safety for system operaation. Alternate isolation valve (1-8807B) opens to provide backup flow path through cross-tie line.	Same method of detection as stated for item #7.	
18. Motor operated gate valve 1-8806	Fails to close on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing flow isolation of HHSI/SI pump suction from RWST. No effect on safety for system operation. Alternate check isolation valve (1-8926) provides backup isolation.	Same method of detection as that stated for item #4.	

TABLE 6.3-10
FAILURE MODE AND EFFECTS ANALYSIS – EMERGENCY CORE COOLING SYSTEM – ACTIVE COMPONENTS

(Sheet 8 of 13)

Component	Failure Mode	ECCS Operation Phase	[a]Effect on System Operation	Failure Detection Method	Remarks
19. Motor operated gate valve 1-LCV-112D (1-LCV-112E analogous)	Fails to close on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing flow isolation of suction of HHSI/CH pumps from RWST. No effect on safety for system operation. Alternate check isolation valve (1-8546) provides backup isolation.	Same method of detection as that stated previously for failure of item during injection phase of ECCS operation.	
20. Residual heat removal pump #1, 1APRH (pump #2 analogous)	Fails to deliver working fluid.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant to the RCS from the Containment Sump. Fluid flow from LHSI/RHR pump #1 will be lost. Minimum recirculation flow requirements for LHSI flow will be met by LHSI/RHR pump #2 delivering working fluid.	Same method of detection as that stated previously for failure of item during injection phase of ECCS operation.	
21. Safety injection pump #1, 1APSI (pump #2 analogous)	Fails to deliver working fluid.	Recirculation - cold or hot legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant to the RCS from the Containment Sump to cold legs of RC loops via RHR and SI pumps. Fluid flow from HHSI/SI pump #1 will be lost. Minimum recirculation flow requirements for HHSI flow will be met by HHSI/SI pump #2 delivering working fluid.	Same method of detection as that stated previously for failure of item during injection phase of ECCS operation.	

TABLE 6.3-10
FAILURE MODE AND EFFECTS ANALYSIS – EMERGENCY CORE COOLING SYSTEM – ACTIVE COMPONENTS

(Sheet 9 of 13)

Component	Failure Mode	ECCS Operation Phase	[a]Effect on System Operation	Failure Detection Method	Remarks
22. Motor operated gate valve 1-8809A	Fails to close on demand.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant to the RCS from the Containment Sump to hot legs of RC loops. Fluid flow from LHSI/RHR pump #1 will continue to flow to cold legs of RC loops. Minimum recirculation flow requirements to hot legs of RC loops will be met by LHSI/RHR pump #2 recirculating fluid to RC hot legs via HHSI/SI pumps.	Same method of detection as that stated for item #4.	
23. Motor operated gate valve 1-8716A (1-8716B analogous)	Fails to open on demand.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant to the RCS from the Containment Sump to the hot legs of RC loops. Fluid flow from LHSI/RHR pump #1 will be lost. Minimum recirculation flow requirements to hot legs of RC loops will be met by LHSI/RHR pump #2 recirculating fluid to RC hot legs via HHSI/SI pumps.	Same method of detection as that stated previously for failure of item during recirculation into cold legs of RC loops ECCS operational phase. In addition, RHR pump discharge pressure (PI-614) at CB.	
24. Motor operated gate valve 1-8840	Fails to open on demand.	Recirculation - hot legs of RC loops.	Same effect on system operation as that stated for item #26.	Same method of detection as that stated for item #7 In addition, RHR pump discharge pressure (PI-614) at CB.	

TABLE 6.3-10
FAILURE MODE AND EFFECTS ANALYSIS – EMERGENCY CORE COOLING SYSTEM – ACTIVE COMPONENTS

(Sheet 10 of 13)

Component	Failure Mode	ECCS Operation Phase	[a]Effect on System Operation	Failure Detection Method	Remarks
25. Motor operated gate valve 1-8809B.	Fails to close on demand.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant to the RCS from the Containment Sump to hot legs of RC loops. Fluid flow from LHSI/RHR pump #2 will continue to flow to cold legs of RC loops. Minimum recirculation flow requirements to hot legs of RC loops will be met by LSHI/RHR pump #1 recirculating fluid to RC hot legs.	Same method of detection as that stated for item #4.	
26. Motor operated gate valve 1-8821A (1-8821B analogous)	Fails to close on demand.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing flow isolation of HHSI/SI pump flow to cold legs of RC loops. No effect on safety for system operation. Alternate isolation valve (1-8835) provides backup isolation against flow to cold legs of RC loops.	Same method of detection as that stated for item #4.	

TABLE 6.3-10
FAILURE MODE AND EFFECTS ANALYSIS – EMERGENCY CORE COOLING SYSTEM – ACTIVE COMPONENTS

(Sheet 11 of 13)

Component	Failure Mode	ECCS Operation Phase	[a]Effect on System Operation	Failure Detection Method	Remarks
27. Motor operated gate valve 1-8802A (1-8802B analogous)	Fails to open on demand.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant to the hot legs of RCS from the Containment Sump via HHSI/SI pumps. Minimum recirculation flow requirements to hot legs of RC loops will be met by LHSI/RHR pump #1 recirculating fluid from Containment Sump to hot legs of RC loops and HHSI pump #2 recirculating fluid to hot legs 1 and 4 of RC loops through the opening of isolation valve 1-8802B.	Same method of detection as that stated for item #7. In addition, SI pump discharge pressure (PI-919) and flow (FI-918) at CB.	
28. Motor operated gate valve 1-8835	Fails to close on demand.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing flow isolation of HHSI/SI pump flow to cold legs of RC loops. No effect on safety for system operation. Alternate isolation valves(1-8821A and 1-8821B) in cross-tie line between HHSI/SI pumps provides backup isolation agains flow to cold legs of RC loops.	Same method of detection as that stated for item #4.	

TABLE 6.3-10
FAILURE MODE AND EFFECTS ANALYSIS – EMERGENCY CORE COOLING SYSTEM – ACTIVE COMPONENTS

(Sheet 12 of 13)

Component	Failure Mode	ECCS Operation Phase	[a]Effect on System Operation	Failure Detection Method	Remarks
29. Residual heat removal pump #1, 1APRH (Pump #2 analogous)	Fails to deliver working fluid.	Recirculation - hot legs of RC loops.	Failure reduces redundancy of providing recirculation of coolant to the RCS from the Containment Sump to the hot legs of RC loops. Fluid flow from LHSI/RHR pump #1 will be lost. Minimum flow requirements to hot legs of RC loop will be met by LHSI/RHR pump #2 recirculating fluid to RC hot legs via HHSI/SI pumps.	Same method of detection as that stated previously for failure of item during injection phase of ECCS operation.	
30. Motor operated globe valve 1-8511A (1-8511B analogous)	Fails to open on demand.	Injection - cold legs of RC loops.	Failure reduces redundancy of providing miniflow to Train A CCP. No effect on safety for system operation.	Valve position indication(open to closed position change) at CB. Valve open position monitor light for group monitoring of components at CB. Periodic tests and inspection in compliance with surveillance requirements of plant's technical specification.	Valve is aligned to open upon actuation by a SI "S" signal. Alternate miniflow valve 1-8511B provided for Train B CCP.
31. Motor operated globe valve 1-8511A (1-8511B analogous)	Fails to close on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of isolation of Train A CCP alternate miniflow line to RWST. No effect on safety for system operation.	Valve position indication (open to closed position change) at CB.	Alternate miniflow isolation valve 1-8512B provided for redundant isolation of Train A CCP mini flow to the RWST.
32. Motor operated globe valve 1-8512B (1-8512A analogous)	Fails to close on demand.	Recirculation - cold legs of RC loops.	Failure reduces redundancy of isolation of Train A CCP alternate miniflow line to RWST. No effect on safety for system operation.	Valve position indication (open to closed position change) at CB.	Alternate miniflow isolation valve 1-8511A provided for redundant isolation of Train A CCP miniflow to the RWST.

TABLE 6.3-10
FAILURE MODE AND EFFECTS ANALYSIS – EMERGENCY CORE COOLING SYSTEM – ACTIVE COMPONENTS

(Sheet 13 of 13)

Component	Failure Mode	ECCS Operation Phase	[a]Effect on System Operation	Failure Detection Method	Remarks
33. Air operated ball valve HV-8220 (HV-8221 analogous)	Fails to close on demand.	Injection - cold legs of RC loops.	Failure reduces redundancy of providing VCT isolation. No effect on safety for system operation; valve (HV-8221) provides backup high point isolation.	Valve position indication (open to closed position change) at CB. Valve close position monitor light for group monotoring of components at CB. Periodic tests and inspection in compliance with surveillance requirements of plant's technical specifications.	Valve is electrically interlocked with LCV-112B (LCV-112C analogous) to close on actuation by SI "S" signal. A "low-low level" VCT signal providing isolation valve LCV-112D (LCV-112E analogous) is at a full open position.

List of abbreviations and acronyms

LOCA - Loss of Coolant Accident

RWST - Refueling Water Storage Tank

BIR - Boron Injection Recirculation

CB - Control Board

SI - Safety Injection

NPSH - Net Positive Suction Head

VCT - Volume Control Tank

CH - Charging

RC - Reactor Coolant

HHSI- High Head Safety Injection

RCS - Reactor Coolant System

LHSI- Low Head Safety Injection

RHR - Residual Heat Removal

a) See list at end of Table for definition of acronyms and abbreviations used.

TABLE 6.3-11
RWST OUTFLOW LARGE BREAK - WORST SINGLE FAILURE[9]

Step (1)	Table 6.3-7 Step	Action	Time Req. Per Step (sec) (3) (5) (10)	RWST Outflow Per Step (gpm) (2) (6) (7)	Cumulative Change in RWST Vol. (gal)
1	-	Reset SI	30	24,694	12,347
2	-	Verify CCW flow from RHR heat exchangers	30	21,596	23,145
3a (4)	-	Verify 8811A&B open (emergency sump to RHRPs)	30	21,245	33,767
3b	1	Close 8812A&B (RWST to RHRPs)	50	20,888	51,174
3c	2	Close 8814A&B, 8813 (SIP miniflow)	40	19,290	64,034
3d	3	Close 8716A&B (RHRP crosstie)	45	18,999	78,282
3e	4	Close 8511A&B, 8512A&B (CCP Alt Miniflow)	40	18,609	90,688
3f	5	Open 8807A&B (SI to Charging Suction Header Crosstie)	45	18,254	104,379
3g (8)	6	Open 8804A&B (RHRP to SIP Suction)	45	17,842	117,760
End of ECCS Switchover Volume			-	-	-
Start of Spray Switchover Volume					
4	7	At 6%, Open HV-4782/HV-4783, Close HV-4758/HV-4759	70	Note 11	12,464

Notes:

(1) Emergency operating procedure steps for transfer to cold leg recirculation. See Table 6.3-7 switchover steps 1 through 6 for a description of the steps 3b through 3g (manual switchover actions for ECCS).

(2) It is assumed that the RHR, SI, charging and containment spray pumps operate at conservative flowrates. Pumped flowrates are assumed to be constant during each step of switchover and the specified number of pumps of each type are operating:

RHR pump	=	2 pumps operating
CCHG pump	=	2 pumps operating
SI pump	=	2 pumps operating
CS pump	=	4 pumps operating

(3) ECCS Valve operating times are maximum operating times from Table 6.3-1.

(4) An allowance of time for valves 8811A/B to automatically open occurs prior to completion of step 1.

(5) Time required to complete the required action for ECCS Switchover includes a conservative 30 seconds for operator response time for each manual procedure.

(6) The flowrate in this column is assumed to occur during the entire time interval for its respective step. This is conservative since valve repositioning may reduce the flowrate during the time interval.

(7) Flow out of the RWST during switchover includes allowances for both pumped flow to the RCS and containment and for backflow to the containment sump.

(8) Following the completion of this step all ECCS pumps are aligned with suction flow from the containment sump with the exception of one RHR pump due to the single failure. The containment spray pumps continue to take suction from the RWST until the RWST level indication is less than or equal to 24% and the operator initiates switchover of the Containment Spray System.

(9) Based on a Large Break LOCA in conjunction with a single failure of one of the RWST to RHR pump isolation valves (e.g., 8812A or 8812B fails to close on demand).

(10) Containment Spray valve operating times are maximum operating times of 20 seconds for HV-4782 and HV-4783 (sump isolation valves) and 30 seconds for HV-4758 and HV-4759 (RWST isolation valves).

(11) Step 4 assumes the operator is anticipating spray switchover after receipt of the empty alarm and can begin the step in 10 seconds. The minimum tank inventory for spray switchover based on 6% indicated level is 13,450 gallons.

6.4 HABITABILITY SYSTEMS

6.4.1 DESIGN BASES

6.4.1.1 Control Room Envelope

The Control Room pressurized envelope, as defined in Section 6.4.2.1, includes the Control Room and all areas adjacent to the Control Room on elevation 831' 6" of the Electrical and Control Building containing plant information and equipment that may be needed during an emergency including kitchen, sanitary facilities, and computer rooms.

Control Room design is based upon the safe occupation of the Control Room envelope during normal operation and for a period of not less than 30 days after a loss-of-coolant accident (LOCA). Habitability systems ensure that the personnel occupying the Control Room during these times will not be exposed to radiation doses exceeding 5 rem whole body gamma dose, 50 rem thyroid dose, and 50 rem beta skin dose. The allowable unprotected beta skin dose may be increased to 75 rem when special protective clothing and eye protection is used. The Control Room is designed in accordance with NRC General Design Criterion (GDC) 19 [1]. The Control Room envelope contains adequate medical supplies and the necessary kitchen and sanitary facilities to sustain plant personnel for a period of 30 days following a DBA. The necessary food and water for five plant personnel for five days will be permanently stored in the Control Room.

6.4.1.2 Radiation and Toxic Gas Protection

Control Room shielding is designed to limit the dose from external sources to a level compatible with the dose criteria given in Subsection 6.4.1.1 based on the inventories given in Table 6.4-1.

The Control Room HVAC system is designed to maintain a positive pressure with respect to the environs during normal and emergency modes of operation.

Airborne radioiodine is limited to levels compatible with the dose criteria given in Subsection 6.4.1.1, based on the radioiodine activities given in Table 6.5-6, and a Containment leak rate of 0.1- percent for the first 24 hr following an accident and one-half this value for the balance of the accident. Refer to Subsection 15.6.5.4 for an analysis of the inhalation dose to the Control Room operators. In the event of a toxic gas release, the control room may be manually isolated from the outside environment by placing the control room ventilation system in the isolation mode. For CPNPP, the probability of simultaneous occurrence of a toxic gas release and radiological release caused by a loss of coolant accident (LOCA) is assumed to be extremely low. Therefore, the event of concurrent releases is not considered in the design basis. See Section 2.2.3 for a discussion of toxic gas releases and analyses.

Airborne radioactive material in the Control Room atmosphere is controlled after an accident by the emergency recirculation filtration units and emergency pressurization filtration units. These atmosphere cleanup units are used in the event of a release of airborne radioactive material. Inlet bubble tight dampers are used in the event of a toxic gas release or fire to provide inlet isolation of either or both trains of outside air into the control room envelope. The Control Room Ventilation System is described in detail in Section 9.4. The limitations of the Control Room environment following a LOCA are listed in Table 6.4-3.

6.4.1.3 Respiratory, Eye, and Skin Protection for Emergencies

Portable self-contained breathing apparatus and protective clothing are provided in the Control Room envelope for use by the plant personnel required to leave this controlled zone during the emergency recirculation mode of operation. There will be an adequate supply of air to sustain the five-man emergency team for a six-hr period. At least one portable self-contained breathing apparatus will be provided for each member of the emergency team. Replenishment capability for the breathing apparatus is also located offsite.

Further air supplies will be replenished as needed by the emergency organization.

Breathable air bottles will be replenished by using the services of one or several commercial air suppliers in the Dallas/Fort Worth metroplex area. Empty bottles will be transported to the commercial air suppliers for replenishment and full bottles will be returned to CPNPP by commercial and/or company vehicle. Once at the site the full air bottles will be distributed to the control room by the members of the Emergency Organization.

6.4.1.4 Habitability System Operation During Emergencies

A detailed description of the Control Room Air-Conditioning System emergency modes of operation is presented in Section 9.4.

6.4.1.5 Emergency Monitors and Control Equipment

Radiation monitors used to switch the Control Room Air-Conditioning System into the emergency recirculation mode are located in the Control Room outside-air intakes. The outside-air intake monitors, located at opposite sides of the Control Building, are used to sample makeup and pressurization air flows introduced into the Control Room envelope. Ionizing smoke detectors are provided in the control room air intakes to provide alarms and indication to the operator of the presence of smoke. Upon detection of smoke in the control room, the operator may manually initiate the isolation mode of the control room ventilation system.

6.4.1.6 Fire Protection Criteria

The Fire Protection System is designed to safeguard equipment and personnel. Combustible materials are excluded as far as practical from the Control Room to lessen the possibility of a fire. The fire stops serve a dual function. Fire stops are incorporated on all cables entering the Control Room to prevent the entry of a fire originating outside the Control Room. They also form a leak boundary which limits exfiltration of air from the Control Room envelope.

Because any fire in the control panels would be very limited, due to the amount of combustible materials present, Control Room evacuation is not considered a necessity; however, remote shutdown capability is available as described in Section 7.4. Codes and guides used in the design of the Fire Protection System are given in Subsection 9.5.1.

6.4.2 SYSTEM DESIGN

6.4.2.1 Definition of Control Room Envelope

The Control Room pressurized envelope consists of the following areas where continuous or frequent operator or technical support personnel occupancy may be required during emergency operation:

Space	Elevation
East Control Room	830'-0"
West Control Room	830'-0"
Console and Control Room Unit 1	830'-0"
Console and Control Room Unit 2	830'-0"
Instrument Room Unit 1	830'-0"
Instrument Room Unit 2	830'-0"
Computer Room Unit 1	830'-0"
Computer Room Unit 2	830'-0"
Shift Manager's Office	830'-0"
Production Supervisor's Office	830'-0"
Corridor	830'-0"
Men's Toilet	830'-0"
Women's Toilet	830'-0"
Kitchen and Janitor Closet	830'-0"
Charts and Supplies Storage Room	830'-0"
Technical Support Center (Office and Corridor)	840'-6"
Offices (2)	840'-6"
Electrical Equipment Corridors (2)	840'-6"

The Control Room envelope also includes the Control Room Air Conditioning System (CRACS) mechanical equipment rooms, Trains A and B, located in the Control Building above the Control Room complex at elevation 854 ft 4 in. These rooms are pressurized and may require infrequent access by a Control Room operator during an emergency condition. The components located in the CRACS mechanical equipment rooms are described in detail in Section 9.4.

6.4.2.2 Ventilation System Design

The Control Room Air-Conditioning and Ventilation System pressurizes the control room with filtered outside air during post-LOCA operation. The Post-LOCA system is designed to control the level of airborne contamination in the Control Room atmosphere and to control the temperature and humidity for personnel safety and comfort. The flow diagrams of the system are shown on Figure 9.4-1. These diagrams include equipment, dampers, instrumentation, and flow paths for normal and emergency operation. Redundant atmosphere cleanup units (emergency filtration units) are used to remove particulate matter and other contaminants from the Control Room air. The design of emergency filtration units is in accordance with NRC Regulatory Guide 1.52 [3] except as noted in Appendix 1A(B). Each filtering unit consists of a particulate, HEPA, iodine adsorber, and HEPA filters, and a booster fan to draw the air through the unit. See Section 9.4 for design parameters and capacities of the filters and related equipment. See Figure 6.4-1 for filtration unit drawing.

The system operation is discussed in Section 9.4. The performance objectives of the Control Room Air Conditioning and Ventilation System and the associated design basis necessary to ensure habitability during and after a LOCA are given in Table 6.4-3.

Redundant emergency pressurization units are used to pressurize the Control Room envelope during emergency recirculation. Redundant inlet bubble tight dampers are installed at each control room ventilation inlet to minimize filtered inleakage into the control room during accident conditions or toxic gas releases.

The emergency pressurization units supply outside air filtered through a particulate, HEPA, iodine adsorber, and HEPA filters to the supply header of the emergency filtration units. A booster fan, demister, and heater are used to circulate the air and maintain the humidity of the incoming outside air below 70 percent. See Figure 6.4-2 for pressurization unit drawing. Seismic classifications for the system are listed by component in Appendix 17A. Layout drawings of the equipment for this area, including doors, corridors, stairwells, and shielding walls, are shown on Figures 1.2-33 and 1.2-34. A detail of the Control Room air inlet is shown on Figure 6.4-3. A description of the instrumentation and controls for the Control Room Air- Conditioning System is given in Section 9.4. Radiation detectors are provided to control ventilation system operation. The redundant train oriented radiation detectors monitor the Control Room ventilation outside-air intakes. A complete description of the emergency filtration and pressurization filter trains is given in Section 6.5.

The Control Room air-conditioning and filtration units, fans, dampers, ductwork, and associated equipment essential to the operation of the Control Room HVAC and Filtration System are located within a missile- protected structure. The Control Room HVAC and filtration air intakes and exhausts are also protected against the damaging effects of a tornado-generated missile.

6.4.2.3 Leaktightness

During the Emergency Recirculation mode, the Control Room envelope is maintained at an overpressure of 0.125-in. water gauge (wg) to prevent infiltration of unfiltered and unmonitored air from the adjacent areas. Any differential greater than 0.125-in. wg causes difficulties in opening and closing doors leading to the area served by the Control Room Air-Conditioning System. During normal operating mode, the Control Room is maintained at a nominal positive pressure of 0.125 in wg with respect to the outdoor environment to minimize dust infiltration. During this mode of operation, other areas in the Control Room envelope are maintained at a slightly positive pressure. This overpressure is maintained by modulating exhaust dampers during normal plant operations and by emergency pressurization units during accident conditions. The boundaries of the Control Room envelope consist of concrete walls and floors which exhibit low leakage characteristics.

To minimize this leakage all joints and penetrations are sealed; all doors are gasketed. All doors are designed to swing inward except the missile resistant door which is airtight and opens outward. In addition, the inlet bubble tight dampers provide assurance of minimal filtered inleakage from the standby train of control room ventilation. The maximum flow rate of the pressurization unit for emergency operation is 800 ft^3/min which is sufficient to pressurize the Control Room envelope to 0.125-in. wg as indicated in Table 6.4-4. However, leakage is expected to be less. Periodic testing of the Control Room envelope is performed to verify this value and to ensure that adequate pressurization is maintained. (See Subsection 6.4.5.) For an

analysis of the dose received by Control Room occupants in the unlikely event of a LOCA, see Subsection 15.6.5.4.

The infiltration rate when the control room is isolated will be much less than the exfiltration rate when pressurized to 0.125 inch water gauge since infiltration is due to wind loadings and much less than half the leakage paths in Table 6.4-4 are exposed to wind loadings.

6.4.2.4 Interaction With Other Zones and Pressure-Containing Equipment

The Control Room envelope is isolated and maintained pressurized during an accident involving the release of radioactive gases in surrounding zones. The Control Room Air-Conditioning System is operated in the emergency recirculation mode, with outside filtered air used to maintain Control Room pressurization. The standby train of control room ventilation is isolated via the use of redundant inlet bubble tight dampers. Doors are designed to open against positive pressure to ensure closure at all times. The use of fire extinguishers located in the Control Room envelope will not yield a hazardous concentration of toxic gas. All piping not connected or related to Control Room equipment is routed outside the pressurized boundary. In the unlikely event of a large release of toxic gas to the outside ambient or surrounding zones, the operator may line up the control room ventilation system in the isolation mode by closing the respective inlet bubble tight dampers. In addition, portable self-contained breathing apparatus are readily available for use by the plant operators.

6.4.2.5 Shielding Design

The shielding design for the Control Room is based on the requirements specified in 10 CFR Part 50, Appendix A, GDC 19. The Control Room is designed to provide radiation protection for personnel occupancy under accident conditions so that no individual will receive exposures in excess of 5-rem whole-body gamma dose, 50-rem thyroid dose and 75-rem unprotected beta skin dose (with special protective clothing and eye protection). To achieve this goal, the shielding design of the Control Room considers airborne contaminants within the Control Room and other DBA sources of radiation. Specifically, these other sources are fission products released to the reactor Containment atmosphere, airborne radioactive contaminants surrounding the Control Room, and sources of radiation caused by potentially contaminated equipment in the vicinity of the Control Room. They are considered to be dominant sources of radiation, and they are among the principal parameters for the shielding design of the Control Room.

Shield thicknesses of structural concrete provided for the Control Room are shown on Figure 12.3-14. The 2 ft-0 in. structural shielding walls surrounding the Control Room, combined with the roof and floor slabs above the Control Room, provide more radiation protection for personnel in the Control Room. In addition to shield thicknesses, distances that separate dominant radiation sources from the Control Room are included on the scaled layout and arrangement drawings of the facility in Section 1.2. Radioactive decay for each isotope of the DBA source is taken into consideration in the analysis of the dose to Control Room occupants shown in Subsection 15.6.5.4. A layout drawing of the Control Room and associated structures is presented on Figure 1.2-33.

DBA sources of radiation surrounding the Control Room and shielding related considerations are presented in Section 12.2, Section 12.3, and Subsection 15.6.5.4. A plan view drawing of the Control Room and associated structures identifying distances and shield thicknesses is shown in Figure 12.3-14.

6.4.3 SYSTEM OPERATIONAL PROCEDURES

The following modes of operation characterize the Control Room Air-Conditioning System:

1. Normal operation

2. Emergency recirculation

3. Emergency ventilation

4. Isolation (emergency recirculation without pressurization)

The Control Room Air-Conditioning System is automatically switched to the emergency recirculation mode upon receipt of signals as outlined in Section 9.4. In addition, the system may be manually switched to the emergency ventilation mode of operation by the operator from the Control Room ventilation panels. This feature enables the removal of traces of smoke that remain in the atmosphere even after the Control Room has been exhausted. The smoke exhaustion from the Control Room and the sequence of automatic events for switching modes are described in Section 9.4.

The Control Room Air-Conditioning System is switched automatically when going from normal operation to the emergency recirculation mode of operation. The sequence of events for switching to emergency recirculation is described in Section 9.4.1.2. The emergency recirculation mode is considered the optimum emergency mode. During this mode of operation, the Control Room envelope is pressurized with filtered outside air to ensure a safe environment for the operators under shutdown conditions. Switching to the emergency ventilation mode can only be done manually, and only from the emergency recirculation mode.

The Control Room Air Conditioning System can only be manually switched to the isolation mode.

The Control Room Air-Conditioning System components are laid out to allow access by Control Room personnel for manual operation of the equipment, particularly dampers. The manual operation of the equipment would be abnormal and it is unlikely that it would have to be utilized.

6.4.4 DESIGN EVALUATIONS

6.4.4.1 Radiological Protection

An evaluation of radiological exposures to plant operators in the event of a DBA is discussed in Subsection 15.6.5.4.

6.4.4.2 Toxic Gas Protection

A hazards analysis for each toxic material was performed as recommended in NRC Regulatory Guide 1.78 [4] and is presented in Section 2.2. The habitability of the Control Room envelope was evaluated to determine if a site-related accident involving a release of hazardous chemicals exceeds the toxicity limits as specified in NRC Regulatory Guide 1.78. For additional information pertaining to this evaluation, see Section 2.2.3.

The Computer Rooms for Unit 1 and Unit 2 and the Technical Support Center, which are located inside the Control Room pressure boundary, employ ten non-seismic non-safety related supplementary cooling units. These areas do not contain safety related equipment and are not needed for continuous occupancy. An analysis based on Reference 10 has been performed to demonstrate that refrigerant concentrations in these areas due to the release of the total refrigerant inventory associated with these units after a seismic event (DBE) will be within the limits specified in ANSI/ASHRAE 15-78 [10].

6.4.4.3 Evaluation of Heating, Ventilation, Air-Conditioning, and Filtration System

The HVAC and Filtration System readiness is ensured by the periodic testing program described in Section 6.4.5. Safe operation is ensured by having redundant equipment for the Control Room HVAC and Filtration System. A complete safety evaluation is given in Section 9.4.

6.4.5 TESTING AND INSPECTION

Preoperational tests are conducted on the Control Room HVAC and Filtration System to ensure that all equipment satisfies the design criteria during all modes of operation. Tests are also performed, as described in Section 9.4 and consistent with the Control Room Envelope Habitability Program in the Technical Specifications, to ensure overall system performance. The leakage tests will be conducted by closing all the access points to the Control Room.

Control Room pressure will be established by controlling the outside air intake flow of the emergency pressurization units until the design pressure is achieved. Should the outside makeup airflow through the emergency pressurization unit exceed the maximum allowable flow of approximately 800 scfm, a survey shall be conducted to locate points of excessive leakage and attempt to seal them. Tests shall be repeated as often as necessary until the above criteria are established.

Control Room pressure is measured by the permanently installed differential pressure transmitters.

The result of the Control Room leak test is considered acceptable if the emergency pressurization airflow does not exceed 800 scfm with the Control Room envelope being maintained at 0.125-in. wg.

Planned leakage tests will be performed to verify that adequate pressurization of the Control Room envelope is maintained during Emergency Recirculation mode. The Control Room envelope will be maintained at 0.125-in. wg positive pressure relative to the outside atmosphere with a maximum makeup airflow of approximately 800 scfm.

In-place testing of air cleaning components will be performed in accordance with test methods and acceptance criteria described in ANSI N510 [7].

Control Room equipment will also be tested in accordance with the methods described in ANSI N509 [6].

Testing requirements, acceptability and frequencies for ESF components are established in the Technical Specifications. The Control Room Emergency Filtration System and the Control Room

Envelope are tested as part of the Control Room Envelope Habitability Program as established in the Technical Specifications.

6.4.6 INSTRUMENTATION REQUIREMENTS

Sufficient indications are provided in the Control Room for the operator to monitor HVAC system performance. Annunciators indicate HVAC system or component malfunctions. See Sections 7.3 and 9.4 for more detailed discussions of the instrumentation.

Fire protection and alarm devices are annunciated in the Control Room as described in Subsection 9.5.1.

Ionization and radiation sensors detect smoke and unsafe levels of radiation in the incoming air. The system automatically switches to emergency recirculation if a radiation detector fails. Subsequent to automatic initiation of the emergency recirculation mode, the operator can regain manual control over the system from the Control Room ventilation panels. A Control Room vertical panel mounted selector switch allows the operator to select normal operation or emergency ventilation modes as required for the operation conditions.

REFERENCES

1. 10 CFR Part 50, Appendix A, General Design Criterion 19, Control Room.

2. NRC Regulatory Guide 1.4, Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Pressurized Water Reactors. Revision 2, June 1974, United States Nuclear Regulatory Commission.

3. NRC Regulatory Guide 1.52, Design, Testing, and Maintenance Criteria for Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants, Revision 1, July 1976, United States Nuclear Regulatory Commission.

4. NRC Regulatory Guide 1.78, Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release, June 1974, United States Nuclear Regulatory Commission.

5. Deleted.

6. ANSI N509, Nuclear Power Plant Air Cleaning Units and Components.

7. ANSI N510, Field Testing of Nuclear Air Cleaning Systems.

8. Leakage Characteristics of Openings for Reactor Housing Components, NAA-SR-MEMO-5137, Atomics International, Div. of North American Aviation, Inc., June 20, 1960.

9. Deleted.

10. ANSI/ASHRAE 15-78, Safety Code for Mechanical Refrigeration.

TABLE 6.4-1
NOBLE GAS AND HALOGEN INVENTORIES RELEASED TO CONTAINMENT
AS THE RESULT OF A MAXIMUM CREDIBLE ACCIDENT

Noble Gases		Halogens	
Curies Released From Core		Curies Released From Core	
Nuclide	(100% Core Inventory)	Nuclide	(50% Core Inventory)[a]
Kr-83m	1.3×10^7		
Kr-85m	3.0×10^7		
Kr-85	7.3×10^5		
Kr-87	5.4×10^7		
Kr-88	7.7×10^7		
		I-131	5.4×10^7
		I-132	7.9×10^7
Xe-131m	7.7×10^5	I-133	1.1×10^8
Xe-133m	3.2×10^7	I-134	1.2×10^8
Xe-133	2.2×10^8	I-135	1.0×10^8
Xe-135m	4.4×10^7		
Xe-135	4.6×10^7		
Xe-138	1.8×10^8		

a) Per R.G. 1.195 half of the iodines in the core are assumed to be available for release to the containment atmosphere immediately.

TABLE 6.4-2
THIS TABLE HAS BEEN DELETED.

TABLE 6.4-3
LIMITATIONS OF CONTROL ROOM ENVIRONMENT

Ambient pressure, in. wg	+0.125[a]
Ambient temperature, FDB	75 ±5
Ambient relative humidity, percent	35 to 50
Noxious substances	Not Applicable
Maximum Radiation doses to operators:	
Whole Body Gamma Dose	5 rem
Beta Skin Dose	75 rem[b]
Thyroid Inhalation Dose	50 rem[c]

a) Except during detection of smoke or toxic gas, at which time the operator may manually initiate control room isolation mode and maintain the control room at atmospheric pressure.

b) The 75 rem limit for beta skin dose is allowed due to the use of protective clothing and eye protection. The dose limit is 50 rem if credit is not taken for protective clothing.

c) Regulatory Guide 1.195 Control Room Thyroid limit.

TABLE 6.4-4
POTENTIAL LEAK PATHS AND THEIR APPROPRIATE LEAKAGE CHARACTERISTICS[a]

Components	Description of Components	Leak Rate (ft^3/min)
Pipe penetrations	For all pipe penetration in the Control Room	Negligible
Cable penetrations	For all cable penetration in the Control Room	Negligible
Doors (assume hollow doors with metal interlocking and gasket-seal weather strip)	Total of twelve doors (Ref. Figures 1.2-33, 34, and 36)	282 (total)
Dampers	CPX-VADPMU-05, CPX-VADPMU-06	9 (total)
	CPX-VADPOU-27, CPX-VADPOU-28	
	All others	Negligible
Redundant inlet bubble tight dampers	Failure of one damper	Negligible
Tornado Blowout Panels	Ten (10) panels 24 (total)	24
Leakage Due to Ingress Egress	All normal ingress and egress to stairwell and interior rooms which serve as the equivalent of vestibules.	10
Ductwork	Uncontrolled Access Area & Office & Service Area Supply & Return ductwork inside the Control Room Pressure boundary	2
Unidentified Leakage	Fan margin	464
TOTAL		800

a) The criteria used to establish leakages is based on a pressure differential of 1/4 in.wg.as specified in NRC Regulatory Guide 1.78[4].

Note:

1. The Control Room is pressurized to 1/8 in. wg. in the Emergency Recirculation mode of operation. The leakrate will be ≤800 ft^3/min at 1/8 in. wg. positive pressure.

2. Total in-leakage is confirmed to be consistent with the Control Room Habitability Program as established in the Technical Specifications.

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEM

Following the postulated DBA, ESF fission-product removal and control systems are required to perform a safety-related function as described in this section.

1. GDC 19 of Appendix A to 10 CFR Part 50 and 10 CFR 100 require adequate radiation protection during access and occupancy of the Control Room and control of radioactive releases to the environment. The secondary atmosphere cleanup systems satisfying GDC 19 and 10 CFR 100 are described in Subsection 6.5.1.

   Since the Containment ventilation system does not perform safeguard functions, i.e., its operation is not required in the event of a postulated LOCA, a description of this system is not provided in this section. The details of the Containment ventilation system are provided in Section 9.4.

   Since the non-ESF units of the Primary Plant Ventilation System do not perform a nuclear safety function, a description of these units is provided in Section 9.4.

2. GDC 41, 42, and 43 of Appendix A to 10 CFR Part 50 require that Containment atmosphere cleanup systems be provided as necessary to reduce the amount of radioactive material released to the environment following a postulated DBA and that these systems be designed to permit appropriate periodic inspection and testing to ensure their integrity, capability, and operability.

   For this purpose, the CSS and the Containment spray chemical additive subsystem are included as ESF in the design of CPNPP and are described in Subsection 6.5.2.

6.5.1 ENGINEERED SAFETY FEATURE (ESF) FILTER SYSTEMS

The atmosphere cleanup systems summarized below are classified as ESF filter systems. Table 6.5-7 indicates which filters perform safety- related functions following a DBA.

	System	Function		Number of Filtration Units	Redundancy
1.	Control room ventilation system	a.	Emergency pressurization	2	100 percent
		b.	Emergency filtration	2	100 percent
2.	Primary plant ventilation ESF exhaust units		Maintenance of Auxiliary, Fuel Handling and Safeguards buildings at a negative pressure during LOCA	4	100 percent

6.5.1.1 Design Bases

As required in GDC 19 of Appendix A to 10 CFR Part 50 and 10 CFR Part 100, the ESF exhaust units are provided to reduce the amount of radioactive material released to the environment following a DBA. As required in GDC 19 of Appendix A to 10 CFR Part 50, the Control Room filtration units are provided to ensure a safe environment and to permit access and occupancy of the Control Room during and after a DBA. The ESF exhaust units are designed to maintain the Auxiliary, Fuel Handling and Safeguards Building at a slightly negative pressure during a LOCA. See Section 9.4.5 for system mode of operation of the ESF ventilation system. Each Control Room emergency pressurization unit is designed to pressurize the Control Room envelope to 0.125-in. wg overpressure based on the combined leak rates shown in Table 6.4-4.

Each emergency filtration unit is designed to handle approximately 16 percent of the required airflow supplied within the Control Room envelope. This percentage is based on an air change rate. The emergency recirculation airflow rate allows the Control Room volume to be filtered approximately once every hour. Control Room area ventilation system operation is explained in Section 9.4.1.

HEPA filters and iodine adsorbers used in these filter trains comply with the construction and efficiency requirements of NRC Regulatory Guide 1.52 (See Appendix 1A(B)). Efficiencies of the HEPA filters and iodine adsorbers are in accordance with Table 9.4-4.

6.5.1.2 System Design

For each ESF atmosphere cleanup system, the design features and fission product removal capability are in compliance with the six positions detailed in NRC Regulatory Guide 1.52 (See Appendix 1A(B)) as shown in Table 6.5-1. Each design item to which exception is taken is justified. Figure 6.5-1 illustrates a typical layout for the ESF atmosphere cleanup units.

6.5.1.3 Design Evaluation

The ESF atmosphere cleanup systems conform to the criteria established in the regulatory positions of NRC Regulatory Guide 1.52 (See Appendix 1A(B)) as shown in Table 6.5-1. Efficiencies of HEPA filters in new condition and data for the iodine adsorbers are presented in Table 9.4-4. Filters are designed to seismic Category I requirements. Redundancy of equipment and power supplies enables the systems to sustain a single, active failure without loss of function during LOCA, loss of offsite power, and normal plant operation.

The safety related ductwork was leak tested per ANSI-N509-1980. The maximum allowable leakage rates are listed in Table 4-3 of this standard. This ductwork is designated as Seismic Category I.

6.5.1.4 Tests and Inspections

Inspection and testing of the ESF atmosphere cleanup units are consistent with the inspection and test requirements outlined in NRC Regulatory Guide 1.52 (See Appendix 1A(B)). These requirements are described in Section 9.4.1.4. The criteria for keeping occupational radiation exposures as low as reasonably achievable (ALARA) during replacement of filters and adsorbers are described in Section 12.3.3.5. Equipment is both factory and in-place tested as per NRC

Regulatory Guide 1.52 (See Appendix 1A(B)). The maintenance procedures are in accordance with position 4.

6.5.1.5 Instrumentation Requirements

Each ESF atmosphere cleanup unit is provided with instrumentation as described in this section.

A pressure indicator connected across the filter train is provided to monitor the overall resistance of each unit. Abnormal differential pressure alarms in the Control Room alert the operator. Local pressure indicators are provided to monitor the resistance of each individual filter bank, while high differential pressure indicates clogged or dirty filters. Each adsorber bed has a temperature-monitoring system which actuates a high temperature alarm in the Control Room in accordance with the temperatures listed in Table 6.5-1. The actions that are subsequently taken are also described in this table.

A pressure differential switch is located across each fan with a Control Room alarm for low fan differential pressure.

It is not necessary to record or monitor filter flow rates and pressure drops from the Control Room because this action is not essential for the ESF Filtration Units to perform their safety related function. Operability assurance of the Filtration Units is maintained in accordance with the Technical Specifications. For those units provided for postulated DBA conditions, alarm annunciators in the Control Room are utilized to monitor design limits (e.g., flow, pressure drops, temperature, etc.) as well as system malfunction (e.g., damper, fan). This design conforms to the intent of NRC Regulatory Guide 1.52 (See Appendix 1A(B)) System Design Criteria, C.2.g. Design details and the system logic are shown on the drawings listed in Section 1.7.

6.5.1.6 Materials

Each ESF filter housing is of all steel construction and welded and it is also brazed or bolted, or a combination of both, in accordance with the design requirements of ORNL-NSIC-65, Design Construction and Testing of High Efficiency Air Filtration Systems for Nuclear Applications. Specific information relating to commercial name and chemical composition of the materials used is provided in Table 9.4-4. HEPA filters and prefilters are fabricated of glass fiber and adsorbers are fabricated of activated charcoal. Ductwork is of sheet metal (galvanized steel) construction. Redundant ESF atmosphere cleanup units are provided for the system outlined in Subsection 6.5.1.1 and are physically separated as shown on Figure 9.4-9 to ensure that any radiolytic or pyrolytic decomposition of the materials used in or on a particular filter system does not interfere with the safe operation of that system or any other ESF system.

6.5.2 CONTAINMENT SPRAY SYSTEMS

This section describes the chemical additive subsystem of the CSS and the spray header locations and volumetric spray coverage. A detailed description of the CSS and its energy removal function can be found in Section 6.2.2.

Containment atmosphere purification and cleanup is accomplished by the CSS. A chemical additive subsystem is provided to inject sodium hydroxide into the spray water. The sodium hydroxide maintains the pH of the spray water at an acceptable value for fission product removal from the post LOCA Containment atmosphere.

6.5.2.1 Design Bases

Following a LOCA, the release of radioactive iodine isotopes (Table 6.5-6) in the gaseous state presents a hazardous condition which is alleviated by the CSS.

The CSS and its chemical additive subsystems are used to remove post-LOCA fission products, principally elemental iodine, from the containment atmosphere. To achieve a fission-product-removal capability which ensures that offsite doses are well below the limits of 10 CFR Part 100, sodium hydroxide solution is added to the borated spray water via the chemical additive subsystem. Component sizing, layout, and the spray solution chemistry are governed by the following principal criteria:

1. Volumetric Containment Coverage with one out of two redundant spray trains in operation must be maximum.

2. The minimum spray fall height above the operating floor is equal to the elevation of the lowest ring header, which is 115 ft 9 in. The average fall height is 126 feet.

3. The system must deliver a minimum flow rate of 5800 gpm to one train of spray nozzles, despite a single failure in the CSS.

4. The system must be capable of permanent removal of iodine from the Containment atmosphere during a LOCA by absorption into the spray droplets and retention in the Containment sump.

5. The Containment spray chemical additive subsystem components are to be designed to seismic Category I requirements.

6. The radioactive iodine isotopes available for release following a LOCA are tabulated in Table 6.5-6.

7. The iodine removal coefficient is calculated in Subsection 6.5.2.3.

6.5.2.2 System Design (for Fission Product Removal)

The CSS has the dual function of removing heat as well as fission-product iodine from the containment atmosphere. Equipment descriptions and principal design parameters for those system components required for the heat removal function are delineated in Section 6.2.2.

The figures mentioned in Subsections 6.5.2.2.2, and 6.5.2.2.4 are based on Unit 1 drawings, but the representation of CSS and nozzle arrangements shown in the figures can be applied to Unit 2 because of its similar design. Specific differences in the total number of containment spray nozzles between Unit 1 and Unit 2 are discussed in Subsection 6.5.2.2.3.

6.5.2.2.1 Modes of Operation

The chemical additive subsystem of the CSS begins operation when the chemical additive tank isolation valves open and sodium hydroxide from the tanks is educted into the borated water. These isolation valves are auto-opened simultaneously with the opening of the containment spray valves. See Section 6.2.2 for details of the modes of operation of the CSS.

The sodium hydroxide is added to the borated water during the injection phase and may continue during the recirculation phase. Vacuum breakers are provided to prevent a negative pressure during chemical injection.

The chemical additive subsystem is isolated automatically to prevent air ingestion when chemical addition motor operated tank isolation valves auto-close on chemical additive tank low level.

An equilibrium sump pH condition exists when both the chemical addition tank isolation valves have closed and the CSS is in the recirculation mode. The spray pH at this point is identical to the equilibrium sump pH.

6.5.2.2.2 Major Components

The mechanical components described in this section are either additions to the CSS or part of the system which has the dual function of heat removal and fission product removal.

The Containment spray chemical additive subsystem is composed of one chemical additive tank, four chemical eductors, connecting piping, and valves. (The Containment spray pumps supply kinetic energy to the motive fluid in the eductors.) The flow diagram of the CSS, including the chemical additive subsystem, is presented on Figure 6.2.2-1. See Table 6.5-2 for component design parameters.

1. Chemical Additive Tank

   The chemical additive tank is sized to hold a sufficient quantity of 28 to 30 weight percent sodium hydroxide solution to maintain equilibrium sump water alkalinity within a design pH range of 8.25 to 10.5. The solution has a crystallization temperature of 35°F.

   The equilibrium sump water is above 8.25. (See Table 6.5-3.) An inert blanket of nitrogen gas is used to cover the sodium hydroxide solution.

2. Containment Spray Chemical Eductors

   The 28 to 30 weight percent sodium hydroxide solution is added to the spray water mainstream by means of liquid jet eductors. A portion of the Containment spray pump discharge is recirculated through the eductor, where the sodium hydroxide is drawn from the chemical additive tank and discharged into the pump suction. The eductors and piping are designed to have a pressure drop compatible with the Containment spray pump suction line in order not to affect the pump NPSH.

3. Piping and Valves

   See Section 6.2.2.

6.5.2.2.3 Containment Spray Headers and Nozzles

The CSS, including the spray headers, is divided into two redundant trains. Each train has headers and nozzles in four regions (A, B, C, and D) of the Containment. For information on the volumes covered by the Containment spray, see Subsection 6.5.2.2.4.

Region A consists of four ring headers per train located within 2 ft of the Containment dome and a minimum of 115 ft 9 in. above the operating floor. Each train in region A contains 274 nozzles for Unit 2 and a minimum 272 nozzles for Unit 1.

Ring 4 is located at a radius of 61 ft 8 in. from the centerline of the Containment with the upper ring (train A) elevation of 1022 ft 10 in. and a lower ring (train B) elevation of 1021 ft 6 in. This ring has 120 (119 for Unit 1) equally spaced nozzles per header, 60 (59 for Unit 1) of which face vertically downward. Of the remaining 60 nozzles, 20 point upward and toward the center of the Containment at a 45 degree angle, with the remaining 40 pointing horizontally toward the center of the Containment.

Ring 3 is located at a radius of 51 ft 4 in. from the Containment centerline with a upper ring (train A) elevation at 1041 ft 3 in. and a lower ring (train B) elevation of 1039 ft 11 in. This ring consists of 60 equally spaced nozzles per header, 40 of which are pointed horizontally toward the center of the Containment. The remaining 20 nozzles are pointed upward and toward the center of the Containment at a 45 degree angle. Ring 2 is located at a radius of 30 ft 3 in. from the Containment centerline with an upper ring (train A) elevation of 1058 ft 8 3/8 in. and a lower ring (train B) elevation of 1057 ft 4 3/8 in. This ring contains 48 (47 for Train A of Unit 1) equally spaced nozzles per header, 32 (31 for Train A of Unit 1) of which are pointed downward. The remaining 16 point upward and toward the center of the Containment at a 45 degree angle.

Ring 1 consists of 46 nozzles and is located at a radius of 13 ft 3 in. from the Containment centerline with an upper ring (train A) elevation of 1065 ft 2 in. and a lower ring (train B) elevation of 1063 ft 10 in. This ring contains 46 nozzles per header with 24 pointing downward and away from the center of the containment at a 45 degree angle, 18 pointing downward, and 4 pointing upward and toward the center of the Containment at a 45 degree angle.

Regions B, C, and D are large open areas below the operating floor of the Containment where if not for Containment spray, airborne fission products could collect during an accident. For additional information on spray volumes, see Subsection 6.5.2.2.4.

The following discussion of containment spray nozzles for Regions B, C and D reveals minor differences between Unit 1 and Unit 2. For Unit 2, a total of eleven spray nozzles have been omitted from Regions B, C and D due to construction material requirements. For the purposes of containment spray iodine removal and thermal effectiveness in containment analysis, these nozzles are considered to be completely obstructed. There is no significant difference between the effective (unobstructed) number of spray nozzles in Unit 1 and Unit 2 as reflected in Table 6.5-5, and there is no significant difference between the analysis results for Unit 1 and Unit 2 due to the containment spray nozzles.

On Unit 1, the two spray headers in region B contain 67 spray nozzles per header. The header on Train A has 67 spray nozzles with 29 pointing downward, 15 pointing downward at 45° below the horizontal, 18 pointing downward at 30° from vertical, 4 pointing downward at 20° from vertical and 1 pointing downward at 40° from vertical.

The header on Train B has 67 spray nozzles with 32 pointing downward, 16 pointing downward 45 degrees from the horizontal, and 19 pointing downward 60 degrees from vertical. On Unit 2, the two spray headers in region B contain 64 spray nozzles on Train A and 67 spray nozzles on Train B. The header on Train A has 30 spray nozzles pointing downward, 15 pointing downward 45 degrees below the horizontal, and 19 pointing downward 30 degrees above the horizontal.

The header on Train B has 67 nozzles with 31 pointing downward, 16 pointing downward at 45 degrees below the horizontal, 17 pointing downward at 30 degrees above the horizontal, 1 pointing downward at 60 degrees above the horizontal, 1 pointing downward at 30 degrees below the horizontal and 1 pointing downward at 36 degrees below the horizontal. For both Unit 1 and Unit 2, these headers are located at an approximate elevation of 900 ft 0 in. and spray an open volume between the secondary shield walls and the Containment liner between elevation 905 ft 9 in. and 860 ft 0 in.

On Unit 1, the two headers in region C contain 14 nozzles per header, all pointing downward and away from the center of the Containment at a 45 degree angle; except two nozzles which are at 52 degrees. On Unit 2, the two spray headers in region C contain 14 spray nozzles on Train A and 13 spray nozzles on Train B, all pointing downward and away from the center of the Containment. The header on Train A has 9 spray nozzles pointing downward 45 degrees from the horizontal, 1 spray nozzle pointing downward 49 degrees from the horizontal, 1 spray nozzle pointing downward 50 degrees from the horizontal, 2 spray nozzles pointing downward 51 degrees from the horizontal, and 1 spray nozzle pointing downward 53 degrees from the horizontal. The header on Train B has 13 spray nozzles pointing downward 45 degrees from the horizontal. For both Unit 1 and Unit 2, these headers are located at an approximate elevation of 855 ft 7 in. and spray an open volume between the secondary shield walls and the Containment liner between elevations 860 ft 0 in. and 832 ft 6 in.

On Unit 1, the two headers in region D contain 27 nozzles per train with four pointing downward and away from the center of the Containment at a 45 degree angle and the remainder pointing downward. On Unit 2, the two spray headers in region D contain 23 spray nozzles on Train A and 24 spray nozzles on Train B, all pointing downward and away from the center of the Containment. The header on Train A has 20 spray nozzles pointing downward and 3 spray nozzles pointing downward 45 degrees from the horizontal. The header on Train B has 21 spray nozzles pointing downward and 3 spray nozzles pointing downward 45 degrees from the horizontal. For both Unit 1 and Unit 2, these headers are located at an approximate elevation of 826 ft 0 in. and spray a space between the secondary shield walls and the Containment liner located between elevations 832 ft 6 in. and 808 ft 0 in.

Spray Engineering Company's Spraco-1713A nozzle has been found acceptable in experiments with Containment spray iodine removal systems. The nozzles are of one piece construction, with a 3/8 in. diameter orifice that produces a hollow cone spray pattern. The nozzle arrangement is designed to provide a maximum coverage inside the Containment. The spray header piping is designed in accordance with the ASME B&PV Code, Section III, Class 2, and the requirements of seismic Category I. The spray nozzles are designed in accordance with manufacturer's standards, which include applicable requirements of ASME B&PV Code, Section III, Class 2. For information on other equipment in the CSS, see Section 6.2.2. For information on drop size, see Section 6.2.2.3.1.

6.5.2.2.4 Containment Coverage

Figure 6.5-2 is a schematic of the Containment that shows the locations of the spray nozzles and sprayed regions, labeled A, B, C, and D.

The calculation of the spray removal coefficient is presented in Subsection 6.5.2.3

The spray system characteristics for each region inside the Containment are described in Table 6.5-5.

1. Bulk Containment Volume

   Region A is covered by 274 (minimum 272 for Unit 1) nozzles per train (Figures 6.5-2 and 6.5-4, Sheets 1 and 2). The nozzle orientation and spacing is such that the volume covered is maximized. The spray density throughout the Containment is as uniform as possible. The design of the lowest ring headers located in the Containment dome is such that the following result:

   a. The minimum fall height is 117 ft 1 in. and 115 ft 9 in. for the lowest ring header of trains A and B, respectively, considering the operating floor at 905 ft 9 in.

   b. The area covered on the operating floor by a nozzle spraying vertically downward is approximately tangent to the Containment wall to minimize spraying of the walls and also to avoid a large unsprayed annulus.

      The ring headers are located less than two ft from the Containment liner to facilitate the piping support design. Each Containment spray train is provided with nozzles spraying horizontally, vertically downward, upward at 45 degrees, and downward at 45 degrees.

      The spray nozzle layout at elevation 905 ft 9 in. is shown on Figures 6.5-2 and 6.5-4, Sheet 3. By using nozzles spraying upward at 45 degrees, the zone between the ring headers and the Containment liner in the dome is covered by spray.

2. Volume Underneath Operating Floor

   Regions B, C, and D (see Figure 6.5-4) (Sheets 3, 4 and 5) are partially covered by spray. The sprayed volume for each region is described in Table 6.5-5.

3. Containment Free Volumes

   The total Containment free volume is 3.031×10^6 ft^3. This volume consists of the following as shown on Figure 6.5-2:

   a. Region A

      The total volume of region A is 2.309×10^6 ft^3 of which 1.665×10^6 ft^3 is covered by spray (72.1 percent), includes the following volumes:

      1. Above operating floor 905 ft 9 in.

      2. Above refueling cavity between 905 ft 9 in. and 860 ft 0 in.

      3. Refueling cavity

4. Fuel storage area

5. Reactor vessel head storage area

6. Steam generator compartments

b. Region B

This volume is 0.168 x 10^6 ft^3, of which 0.035 x 10^6 ft^3 (20.9 percent) are covered by spray. The volume is located between 905 ft 9 in. and 860 ft 0 in. (between the secondary shield wall and the Containment wall).

c. Region C

This volume is 0.073 x 10^6 ft^3, of which 0.0026 x 10^6 ft^3 (3.6 percent) are covered by spray. The volume is located between 860 ft 0 in. and 832 ft 6 in. (between the secondary shield wall and the Containment wall).

d. Region D

This volume is 0.125 x 10^6 ft^3, of which 0.0034 x 10^6 ft^3 (2.7 percent) are covered by spray. The volume is located between 832 ft 6 in. and 808 ft 0 in. (between the secondary shield wall and the Containment wall).

e. Region E

All sub-volumes included in the Containment total free volume and not calculated to be part of Regions A-D are combined together in Region E as "unsprayed volume". These sub-volumes are separate from each other, but linked to Regions A-D by flow paths which permit varying degrees of convective mixing. The sub-volumes which are less open to convective mixing, such as the reactor cavity, are separated from the Containment liner (and potential leakage paths) by the six inch radial gap which is open to convective mixing. Region E has a total volume of 0.356 x 10^6 ft^3 and includes the following compartments:

1. Cavity beneath reactor vessel

2. Elevator

3. Rod position indication room (860 ft 0 in.)

4. Pressurizer relief tank compartment

5. Pressurizer compartment

6. In-core instrumentation room (849 ft 0 in.)

7. Seal table room (832 ft 6 in.)

8. Neutron flux detector operating room (808 ft 0 in.)

9. Heat exchanger compartments

10. Miscellaneous passageways

The effective spray volume consists of the sprayed volumes in regions A, B, C, and D.

The total sprayed volume from all sprayed regions is 1.706×10^6 ft^3. This volume represents 56.3 percent of the Containment free volume.

Regions A, B, C and D are linked to each other and to the various sub-regions which comprise region E via numerous air flowpaths (e.g. six inch radial gap between the concrete floors and the inner wall of the containment building, gated doors, floor grating, etc.). These flowpaths are sufficient to allow an assumption that convective mixing occurs between the sprayed and unsprayed volumes at a rate of two turnovers per hour.

6.5.2.3 Design Evaluation

1. Iodine Absorption

The Containment spray chemical additive subsystem incorporates provisions to enhance absorption of radioactive iodine from the Containment atmosphere by the Containment spray droplets. A favorable alkalinity level is established by the addition of sodium hydroxide solution to the borated water. This alkalinity increases the solubility of iodine to the extent that the rate of iodine absorption is mainly limited by the mass transfer rate through the gas film surrounding the spray water droplets. Furthermore, the alkalinity level is also favorable in preventing the dissolved iodine from escaping from the Containment sump water.

Radioiodine, in its various forms, is the fission product of primary concern in the evaluation of a LOCA. The major benefit of the Containment spray is its capacity to absorb elemental iodine from the Containment atmosphere. To enhance the iodine-absorption capacity of the spray, the spray solution is adjusted to an alkaline pH which promotes iodine hydrolysis to nonvolatile forms.

According to the known behavior of elemental iodine in highly dilute solutions, the hydrolysis reaction

$$I_2 + OH \rightarrow HIO + I$$

is nearly completed at pH>8. The iodine form is highly soluble, and HIO readily undergoes additional reactions to form iodate.

The overall reaction is

$$3I_2 + 3H_2O \rightarrow 5HI + HIO_3$$

2. Solution pH

Following a design basis accident, the spray pH may be as low as 4.5 or as high as 12.5 for a short duration under bounding single failure scenarios. The sump and therefore spray attains an equilibrium pH value ranging between 8.25 to 9.2. The parameter variations used to calculate the equilibrium pH values are given in Table 6.5-3. However, long term sump pH valves used for iodine retention are not impacted by this short term out of range pH.

To determine the Containment sump solution pH, all sources of borated water such as the RCS accumulators, the RWST, and system piping are considered. The mixing of the Containment spray solution and the spilled water is considered complete in the Containment sumps.

3. Containment Spray Iodine Removal Coefficient

The spray effectiveness evaluation was based on the experimental summaries and modeling presented in WASH 1329, A Review of Mathematical Models for Predicting Spray Removal of Fission Products in Reactor Containment Vessels [1], as recommended in Standard Review Plan 6.5.2.

The removal of radioiodine is considered to be a first order with respect to iodine concentration and is mathematically described as follows:

$$\frac{dC}{dt} = -\lambda C \qquad (6.5\text{-}1)$$

which integrates to

$$C = C_o e^{-\lambda t} \qquad (6.5\text{-}2)$$

where

C = iodine concentration in the containment atmosphere

λ = iodine removal coefficient

C_o = initial iodine concentration in the containment atmosphere

t = time after the spray operation

Pursuant to WASH 1329, the removal coefficient of elemental iodine by sprays with a sodium hydroxide composition has been evaluated.

The elemental iodine removal coefficient is related to the spray parameter as follows:

$$\lambda = \frac{6VdhF}{VdU} \qquad (6.5\text{-}3)$$

where

V_d = overall deposition velocity

h = spray drop fall height

F = spray flow rate

V = Containment sprayed volume

U = spray drop terminal velocity

d = drop diameter

The deposition velocity V is evaluated from

$$\frac{1}{Vd} = \frac{1}{Kg} + \frac{1}{HK_L} \qquad (6.5\text{-}4)$$

where

V_d = overall deposition velocity

k_g = gas film mass transfer coefficient

k_L = liquid film mass transfer coefficient

H = iodine partition coefficient

The liquid film mass transfer coefficient is predicted by:

$$k_L = \frac{2\pi D_L}{3d} \qquad (6.5\text{-}5)$$

where

D_L = diffusivity of iodine in water

d = drop diameter

The gas film mass transfer coefficient is predicted by:

$$Kg = \frac{D}{d}(2.0 + 0.6R_e^{0.5}S_c^{0.33}) \qquad (6.5\text{-}6)$$

where

D = diffusivity of iodine in gas phase

R_e = Reynolds number

S_c = Schmidt number

The mathematical model described in Equations (6.5-1) through (6.5-6) is evaluated numerically using input parameters which are chosen to yield conservative estimates of washout rates. The washout rate predicted from Equation (6.5-3) is reduced by numerical factors which account for physical factors not directly included in the model. The parameters, related factors, and assumptions are described in the following paragraphs:

a. The removal mechanisms are assumed to be first order behavior which required the removal process to be independent of time and iodine concentration. Physical properties such as density, viscosity, diffusivity, as well as the partition coefficient H, must be independent of iodine concentration at the very low iodine concentration involved in Containment sprays. However, the iodine partition coefficient is not. Conservatively, a small value of 5000 is chosen for H as recommended in WASH 1329 [1]. To be independent of time, there must be no approach to an equilibrium between the iodine concentration in the containment atmosphere and in the spray solution. This assumption is conservative because of the assumption that the elemental iodine removal effectiveness of the spray system will cease after a maximum decontamination factor for 100 for the first two hr in the containment atmosphere has been achieved.

b. The radioiodine is conservatively assumed to be instantaneously released to the Containment atmosphere at the time of the accident.

c. The gas space in the sprayed portion of each region is perfectly mixed so that the drops are exposed to the same iodine concentration through its entire fall height.

d. Drops are assumed to fall vertically at their terminal velocity.

e. The drop fall height assumed for each region is the minimum fall height for the region.

f. Steam condensation effects are neglected. Based on an analysis contained in WASH 1329, steam condensation on the drops results in a negligible increase in washout. For the Spraco 1713A Nozzle, the effective drop diameter was conservatively assumed to be 1500 microns.

g. Impingement of the spray drops on the Containment wall will lower the washout by a maximum of ten percent, and any buildup of fine drops has a negligible effect on washout.

h. Calculation is done at a conservative temperature of 100°C.

i. D, R_e, S_c, and U are calculated using the methodology on ORNL-TM-1911, Removal Elemental Iodine from Steam - Air Atmosphere by Reactive Spray [2], and D_L is computed using the methodology of Reference [3].

The iodine removal coefficient is evaluated in accordance with the CSS characteristics delineated in Table 6.5-5.

The spray washout model for particulate iodine is represented in equation form as follows:

$$\lambda\rho = \frac{3hEF}{2dV} \qquad (6.5\text{-}7)$$

where

λp = particulate iodine removal coefficient

h = drop fall height

E = total collection efficiency for a single drop

F = spray flow rate

d = drop diameter

V = containment spray volume

This model embodies assumptions equivalent to most assumptions applied to the washout of elemental iodine. The drop collection efficiency is modeled using a value of 10/m (this value is reduced to 1.0/m after the airborne activity is reduced by a factor of 50). The particulate iodine removal coefficient is listed in Table 6.5-5.

For each region calculated, elemental iodine removal coefficients are above 10 hr^{-1}, respectively. The removal coefficients used in LOCA offsite dose calculation (see Section 15.6.5.3) have been limited to a maximum value of 10 hr^{-1} for elemental iodine [1]. The most conservative particulate iodine removal coefficient 11.4 hr^{-1} is also taken into account on the LOCA offsite dose calculation until the inventory is reduced by a factor of 50, after which a value of 1.14 hr^{-1} is used.

4. Single Failure Analysis

The containment spray chemical additive subsystem is designed to function reliably in the event of a LOCA. Redundancy requirements are met by providing two electrically

separated motor-operated chemical additive tank stop valves in parallel such that, in case of single active failure, there still remains a full 100-percent capacity to reduce the elemental iodine concentration inside the Containment. In addition, an air-operated normally open valve is provided in series with each of the motor-operated valves to ensure that the line may be closed when the chemical additive tank is empty and thus prevent air from being entrained in the suction of the containment spray pumps. There is no credit for the air-operated valve (passive, fails open) in the pH analysis. A single failure analysis is presented in Table 6.5-4 for the chemical additive subsystem.

Reproductibility of subsystem design parameters is ensured by using performance tested chemical eductors and spray nozzles, as well as constant speed containment spray pumps. Furthermore, the only moving parts in the system are those associated with the pumps, valves, and motors. System component parameters are verified by testing.

6.5.2.4 Tests and Inspections

1. Preoperational Tests

Component testing is performed on the motor-operated stop valves at the outlet of the chemical additive tank because these are the only active components of the Containment spray chemical additive subsystem.

Testing is performed on the Containment spray chemical additive subsystem in conjunction with the testing of the CSS as described in Section 6.2.2.4. A test signal simulating the Containment spray actuation signal is artificially initiated to demonstrate the operation of the spray system up to the isolation valves on the pump discharge lines. The isolation valves are closed for the test and are checked separately. The functional test of the onsite power system described in Chapter 8 demonstrates proper transfer to the emergency diesel generator power source in the event of a loss of offsite power. The chemical eductors are tested in the manufacturer's shop with a fluid comparable to the chemical additive solution. Preoperational testing is conducted using water as a test fluid. The Chemical Additive Tank (CAT) is aligned to the eductors and acceptable flow is demonstrated for each eductor over the range of the CAT levels.

For evaluation of test data, equivalent chemical solution and water flows are calculated accounting for physical differences (e.g., density, viscosity)

2. Inservice Surveillance

Inservice surveillance of the chemical eductors and chemical additive tank and associated valves is performed in a manner similar to preoperational testing as discussed above, except as described below.

Routine testing of the chemical additive system components is performed periodically, during shutdown and refueling operations.

The test line from the RWST to the chemical additive discharge line, upstream from the chemical additive flow measuring element, is opened, along with the full flow test line from the discharge of the Containment spray pumps which runs back to the RWST. The Containment spray pumps are started from the Control Room. Borated water flows from

the RWST through the spray additive flowmeters into the suction of the eductors. The fluid then flows through the Containment spray pump test line.

A pressure gauge located upstream from the eductor and flow throttling in the test line from the RWST are used to simulate the suction head from the chemical additive tank.

The chemical additive tank isolation valves are operated periodically for testing, during shutdown and refueling operations. The contents of the tank are periodically sampled to determine that the required concentration is maintained.

During these tests, the equipment is visually inspected for leaks. Leaking seals, packing, or flanges are corrected to eliminate the leak. Valves are operated and inspected after any maintenance to ensure proper operation. The inservice surveillance testing of the onsite power system discussed in Section 8.3 demonstrates proper transfer to the emergency diesel generator power source in the event of a loss of offsite power.

6.5.2.5 Instrumentation Requirements

The logic for initiation of the CSS operation is presented in Sections 7.2 and 7.3 and on Figure 7.2-1. The following describes the instrumentation which is employed for monitoring the chemical additive subsystem during normal plant operation and during postaccident operation. All alarms are annunciated in the Control Room.

1. Containment Spray Chemical Additive Tank Pressure

   A locally mounted indicator on the nitrogen line provides the means to continuously monitor chemical additive tank pressure. High and low pressure are alarmed in the Control Room from a pressure switch on the nitrogen line.

2. Chemical Additive Flow and Pressure

   A flow element is located in the discharge line from the chemical additive tank. Readout is local to provide flow indication during flow testing described in 6.5.2.4, above.

   A low flow alarm is provided in the Control Room. Pressure indication is provided in each chemical eductor suction line.

3. Chemical Additive Tank Level

   Two level switches automatically close the motor operated tank isolation valves when low level is reached. If one isolation valve does not operate and tanks continue to empty, a second air operated valve closes at a lower level to isolate the tank. A level transmitter provides indication and low level alarm in the Control Room alerting the operator to check the tank isolation valves. As noted in the single failure analysis, above, the motor operated valves perform the safety function.

6.5.2.6 Materials

The materials used in the CSS components are listed in Table 6.2-4.

6.5.3 FISSION PRODUCT CONTROL SYSTEMS

6.5.3.1 Primary Containment

The primary Containment is equipped with a Containment Spray System. The Containment Spray System is designed primarily to remove heat generated within the primary containment following a DBA. The Containment Spray System, which also serves as a fission product control system, is described in detail in Section 6.5.2.

The Containment Spray System is the only primary containment fission product control system designed to function after a DBA.

6.5.3.2 Secondary Containments

There are no secondary containments installed at the CPNPP. The primary containment is the sole means relied upon to contain radioactive material following an accident.

6.5.4 ICE CONDENSER AS A FISSION PRODUCT CLEANUP SYSTEM

Ice condensers are not installed at the CPNPP.

REFERENCES

1. Postma, A. K., and Pasedag, W. F., WASH 1329, A Review of Mathematical Models for Predicting Spray Removal of Fission Products in Reactor Containment Vessels, June 1974.

2. Parshy, Jr., L. F., ORNL-TM-1911, Removal of Elemental Iodine from Steam - Air Atmosphere by Reactive Sprays, October 1967.

3. Griffiths, V., UKAEA Health and Safety Branch Report AHSE (S)-R- 45, The Removal of Iodine from the Atmosphere by Sprays, 1963.

TABLE 6.5-1
ANALYSIS OF ENGINEERED SAFETY FEATURE ATMOSPHERE CLEANUP SYSTEMS WITH RESPECT TO EACH POSITION OF NRC REGULATORY GUIDE 1.52, Rev. 1

(Sheet 1 of 5)

Criteria	Control Room HVAC System 1. Emergency Pressurization Atmospheric Cleanup System [a] 2. Emergency Filtration Atmospheric Cleanup System [a]	Primary Plant Exhaust Atmoshperic Cleanup System[a] (ESF) [b]
Regulatory Position 1: Environmental Design Criteria		
a. Each ESF atmoshpere cleanup system is based on conditions resulting from DBA.	Designed to limit dose resulting from DBA within limits of GDC 19	System is designed to contain radioactive particulates and radioactive iodine resulting from a fuel accident or ESF component leakage.
b. System design is based on 30-day integrated radiation dose.	Yes; filters are designed for a 30-day integrated dose.	Yes
c. Adsorber design is based on iodine concentration.	Yes	Yes
d. Compatibility of atmosphere cleanup system with other ESFs	Yes	Yes
e. Components of system designed for both the lowest and highest outdoor temperatures	Yes	Yes
Regulatory Position 2: System Design Criteria		
a. Redundancy of atmosphere cleanup system if designed for mitigation of accident doses	Two filter trains, heater, mist eliminators, particulate, HEPA filters, fan, and housing are the components included in the design of each unit, with redundancy in active and passive components. Heater and mist eliminator are not included on emergency filtration units.	Two filter trains, heater mist eliminator, HEPA and carbon filters, fan, and the components included in the design of each unit, with redundancy in active and passive components.
b. Physical separation of redundant atmosphere cleanup systems	Yes	Yes
c. Atmosphere cleanup system designated seismic Category I to prevent release of fission products	Yes	Yes
d. Atmosphere cleanup system pressure surge protection	NA	NA

TABLE 6.5-1
ANALYSIS OF ENGINEERED SAFETY FEATURE ATMOSPHERE CLEANUP SYSTEMS WITH RESPECT TO EACH POSITION OF NRC REGULATORY GUIDE 1.52, Rev. 1

(Sheet 2 of 5)

Criteria		Control Room HVAC System 1. Emergency Pressurization Atmospheric Cleanup System [a] 2. Emergency Filtration Atmospheric Cleanup System [a]	Primary Plant Exhaust Atmoshperic Cleanup System[a] (ESF) [b]
e.	Atmoshpere cleanup system construction materials; effective performance if exposed to radiation	Yes	Yes
f.	Maximum and (required) volumetric airflow rate per atmosphere cleanup system train, respectively**	Filtration units: 8000 ft^3/min (8000 ft^3/min) Pressurization units: 1000 ft^3/min (800 ft^3/min)	15,000 ft^3/min (15,000 ft^3/min)
g.	Atmosphere cleanup system instrumentation provided	Yes[c][d]	Yes[c][d]
h.	Electrical distribution and power supply conforming to IEEE Standards	Yes	Yes
i.	Radiation protection for workers in order to perform maintenance	Removal of individual components and ensuring that exposure to operating personnel is ALARA.	Removal of individual components and ensuring that exposure to operating personnel is ALARA.
j.	Minimization of meteorological effects on outdoor air intakes	Yes	Yes
k.	Atmosphere cleanup system housing and ductwork maximum total leak rate limitations	In accordance with ANSI N-509	In accordance with ANSI N-509.

TABLE 6.5-1
ANALYSIS OF ENGINEERED SAFETY FEATURE ATMOSPHERE CLEANUP SYSTEMS WITH RESPECT TO EACH POSITION OF NRC REGULATORY GUIDE 1.52, Rev. 1

(Sheet 3 of 5)

Criteria		Control Room HVAC System 1. Emergency Pressurization Atmospheric Cleanup System [a] 2. Emergency Filtration Atmospheric Cleanup System [a]	Primary Plant Exhaust Atmoshperic Cleanup System[a] (ESF) [b]
Regulatory Position 3: Component Design Criteria and Qualification Testing			
a.	Demister performance and qualification requirements	Demisters[e] are provided for the pressurization units.	A loss of fuel[e] pool cooling may result in relative humidity to 100 percent. Demister is necessary.
b.	Effective operating condition on adsorption units	Yes; pressurization units equipped with heaters. Emergency filtration unit relative humidity controlled by Control Room air conditioning system.	Yes; units are equipped with heaters.
c.	Requirements of prefilter materials subjected to radiation	Materials used in prefilters withstand the radiation levels and environmental conditions prevalent during the postulated DBA, based on the use of Cambridge Model 3 CP-90-24-24-12 or equal.	Materials used in prefilters withstand the radiation levels and evironmental conditions prevalent during the posulated DBA, based on the use of Cambridge Model 3 CP-90-24-24-12 or equal.
d.	HEPA filter requirements and standards performance	Yes; based on the use of Flanders 1500-cfm filter model number 7083-NL or equal.	Yes; based on the use of Flanders 1500-cfm filter model number 7083-NL or equal.
e.	Filter and adsorber mounting frames (design and construction)	In accordance with ANSI N-509	In accordance with ANSI N-509
f.	Filter and adsorber bank arrangement recommendations	In accordance with ANSI N-509[d]	In accordance with ANSI N-509[d]
g.	System filter housings design and construction	In accordance with ANSI N-509[f]	In accordance with ANSI N-509[f]
h.	Water drain recommendations	In accordance with ORNL-NSIC-65[g]	In accordance with ORNL-NSCI-65[g][h]
i.	Removal of gaseous iodine by absorber (carbon) material	Carbon efficiency in accordance with Table 5-1, N509-1976	Carbon efficiency in accordance with Table 5-1, N509-1976
j.	Pleated-bed absorbent canister design recommendations	Yes	Yes

TABLE 6.5-1
ANALYSIS OF ENGINEERED SAFETY FEATURE ATMOSPHERE CLEANUP SYSTEMS WITH RESPECT TO EACH POSITION OF NRC REGULATORY GUIDE 1.52, Rev. 1

(Sheet 4 of 5)

Criteria		Control Room HVAC System 1. Emergency Pressurization Atmospheric Cleanup System [a] 2. Emergency Filtration Atmospheric Cleanup System [a]	Primary Plant Exhaust Atmoshperic Cleanup System[a] (ESF) [b]
k.	Fire prevention in adsorber	Ignition >600°F; desorption >300°F; isolation of the affected unit prior to desorption, water spray to inhibit adsorber fires	Ignition >600°F; desorption >300°F; isolation of the affected unit prior to desorption, water spray to inhibit adsorber fires
l.	System fans provided with sufficient capacity and pressure	Yes	Yes
m.	Atmosphere cleanup system fan or blower operates under the environmental conditions postulated.	Yes	Yes
n.	Ductwork designed in accordance with recommendations	Yes; meets requirements of ANSI N-509[d]	Yes; meets requirements of ANSI N-509[d]
o.	System contains a minimum of ledges, protrusions, crevices, and similar items which impede personnel or create a hazard.	Yes	Yes
Regulatory Position 4: Maintenance			
a.	Personnel safety and ready removal of the elements	Yes	Yes
b.	Easy access of components	Yes	Yes
c.	Definite mounting frame separation distances	Yes[i]	Yes[i]
d.	Permanent test probes with external connections	Test Ports are provided externally[d]	Test Ports are provided externally[d]
e.	Periodic operation of standby atmosphere cleanup system	Yes; cyclic use of components	Yes; cyclic use of components

TABLE 6.5-1
ANALYSIS OF ENGINEERED SAFETY FEATURE ATMOSPHERE CLEANUP SYSTEMS WITH RESPECT TO EACH POSITION OF NRC REGULATORY GUIDE 1.52, Rev. 1

(Sheet 5 of 5)

Criteria	Control Room HVAC System 1. Emergency Pressurization Atmospheric Cleanup System [a] 2. Emergency Filtration Atmospheric Cleanup System [a]	Primary Plant Exhaust Atmoshperic Cleanup System[a] (ESF) [b]
f. Atmosphere cleanup system components installed after active construction	Yes	Yes
Regulatory Position 5: In-Place Testing Criteria[j]		
a. In-place testing of atmosphere cleanup system	Acceptance tests and periodic tests during plant operation in accordance with ANSI-N510, 1980	Acceptance tests and periodic tests during operation in accordance with ANSI-N510 1980
b. Testing the airflow distribution to the filters (HFPA and adsorbers)	Acceptance tests and periodic tests during plant operation in accordance with ANSI-N510, 1980. For the control room pressurization unit, this is not necessary since there is only one HEPA filter.	Acceptance tests and periodic tests during operation in accordance with ANSI-N510, 1980
c. The in-place testing of HEPA filters conforms to ANSI standards or is replaced.	Acceptance tests and periodic tests during plant operation in accordance with ANSI-N510, 1980	Acceptance tests and periodic tests during plant operation in accordance with ANSI-N510, 1980
d. The adsorbers are leak-tested.	Acceptance tests and periodic tests during plant operation in accordance with ANSI-N510, 1980	Acceptance tests and periodic tests during operation in accordance with ANSI-N510, 1980
Regulatory Position 6: Laboratory Testing Criteria for Activated Carbon[f][j]		
a. If the activated carbon adsorber meets the regulatory requirements, the adsorber section is assigned the decontamination efficiencies. If not, the carbon is not used in ESF adsorbers.	Testing of samples to determine efficiencies (in accordance with ASTM D3803-1989)	Testing of samples to determine efficiencies (in accordance with ASTM D3803-1989)
b. The efficiency of the activated carbon adsorber section is determined by laboratory testing of representative samples of the activated carbon exposed simultaneously to the same service conditions as the adsorber section.	Yes; see Subsection 6.5.1.4. The methyl iodide penetration allowable for the control room pressurization and emergency filtration units is 0.5% by using safety factor 2 and 99% efficiency of the filter units.	Yes; see Subsection 6.5.1.4. The methyl iodide penetration allowable for the primary plant ventilation filtration units is 2.5% by using safety factor 2 and 95% efficiency of the filter units.

a) Components of Atmospheric Cleanup Systems are as described in Regulatory Guide 1.52.

b) Features of the modular exhaust filtration system used as follows: These units are connected in parallel. Four units of the modular system are considered as ESF units.

c) It is not necessary to record or monitor filter flow rates and pressure drops from the Control Room because this action is not essential for the ESF Filtration Units to perform their safety related function. Operability assurance of the Filtration Units is maintained in accordance with the Technical Specifications. For those units provided for postulated DBA conditions, alarm annunciators in the Control Room are utilized to monitor design limits (e.g., flow, pressure drops, temperature, etc.) as well as system malfunction (e.g., damper, fan).

d) See Appendix 1A(B) for additional information.

e) Demisters are designed in accordance with the recommendations of Mine Safety Analysis Research 71-45 and meet Underwriters; Laboratories, Inc., Class I requirements.

f) In lieu of the standards and their revisions recommended by Regulatory Guide 1.52, ANSI N509-1980 has been used. In-place testing of the HEPA filter banks and adsorber will be required following any significant painting, fire or chemical release. This design conforms to the intent of NRC Regulatory Guide 1.52, Revision 2 (03/78). See Appendix 1A(B).

g) Check valves have been utilized on some drains in lieu of seals or traps. See Appendix 1A(B).

h) The drains have not been provided with seals, traps or check valves in the demister compartments. Any minimal airflow through the demister drains will be filtered prior to discharge through the stack. See Appendix 1A(B).

i) There are cases where the minimum spacing requirements are not met. See Appendix 1A(B) for the discussion on Regulatory Guide 1.52.

j) In lieu of the standards and their revisions recommended Regulatory Guide 1.52, ANSI N510-1980 has been used. In-place testing of the HEPA filter banks and adsorber will be required following any significant painting, fire or chemical release. This design conforms to the intent of NRC Regulatory Guide 1.52, Revision 2 (03/78). See Appendix 1A(B).

TABLE 6.5-2
CONTAINMENT SPRAY CHEMICAL ADDITIVE SUBSYSTEM COMPONENT
DESIGN PARAMETERS

(Sheet 1 of 2)

1. Chemical Additive Tank	
Quantity	One
Volume (empty), gal	5500
Volume of contents, gal	4500
Contents	Sodium hydroxide
Concentration, % by weight	30
Design pressure, psig	15
Design temperature, F	200
2. Chemical Eductors	
Quantity	Four
Motive Fluid	Borated water
Flow rate, gpm	100
Concentration, ppm	2400
Design pressure, psig	325
Design temperature, F	300
Suction Fluid	Sodium hydroxide solution
Flow rate, gpm	45
Concentration, % by weight	30
Design pressure	Hydraulic head
Design temperature	ambient
Specific gravity	1.34
Viscosity, cP	10

TABLE 6.5-2
CONTAINMENT SPRAY CHEMICAL ADDITIVE SUBSYSTEM COMPONENT
DESIGN PARAMETERS

(Sheet 2 of 2)

3. Piping and Valves	
Chemical Supply Piping	
Design Pressure, psig	150
Design temperature	200
Eductor Piping	
Design pressure, psig	325
Design temperature, F	300

TABLE 6.5-3
PARAMETER RANGES USED FOR CALCULATION OF EQUILIBRIUM SUMP SOLUTION pH

	Minimum pH 8.25	Maximum pH 9.7
RWST Volume (gal)	506000 (Approx.)	316000 (Approx.)
Boron Concentration in RWST (ppm)	2600	2400
Reactor Coolant System Liquid Volume (gal)	88233	0
Boron Concentration in RCS (ppm)	1850	N/A
Safety Injection Accumulator Volume (gal)	26388	24476
Volume of Fluid in Chemical Additive Tank (CAT) (gal)	4900	5314
NaOH Concentration in Chemical Additive Tank (WT%)	28	30
Single active failure postulated	None	Failure of CAT isolation valve to close at Low Level

TABLE 6.5-4
SINGLE FAILURE ANALYSIS CONTAINMENT SPRAY CHEMICAL ADDITIVE SUBSYSTEM

Component	Malfunction	Remarks
Motor-operated chemical additive tank stop valve	Valve fails to open	Two valves are provided; operation of one is required.
	Valve fails to close	Two valves are provided; operation of one is required.
Chemical eductor	Eductor orifice is clogged.	Four eductors are provided (one pair for each train); one pair is required to operate.

TABLE 6.5-5
CONTAINMENT SPRAY SYSTEM CHARACTERISTICS

	Regions					
	A	B	C	D	E	Total
Total volume, ft^3	2,309,461	167,645	72,686	124,910	356,333	3,031,035
Sprayed containment volumes, ft^3	1,664,901	35,040	2,640	3,364	0.0	1,705,945
Unsprayed containment volumes ft^3	644,560	132,605	70,046	121,546	356,333	1,325,090
Spray drops fall height, ft	126[a]	38	23	20	-	-
Number of nozzles per train [b]	274 (272-Unit 1 train A) (273-Unit 1 train B)	67 [36][c] (64-Unit 2 train A) (67-Unit 2 train B)	14 [5][c] (14-Unit 2 train A) (13-Unit 2 train B)	27 [10][c] (23-Unit 2 train A) (24-Unit 2 train B)	-	382 (380-Unit 1 train A) (381-Unit 1 train B) (375-Unit 2 train A) (378-Unit 2 train B)
Elemental iodine removal coefficient, hr^{-1}[d]	60.4	106.9	119.4	162.9		
Particulate iodine removal coefficient, hr^{-1}	11.4	38.7	63.2	76.3	-	-

a) Average value

b) 15.2 gpm/nozzle

c) Unobstructed spray nozzle (train A)

d) Maximum X_e allowed to be used in analysis is 10 hr^{-1}.

TABLE 6.5-6
RADIOACTIVE IODINE ISOTOPES AVAILABLE FOR RELEASE TO OUTSIDE ATMOSPHERE FROM THE CONTAINMENT FOLLOWING A LOCA

Isotope	Activity[a] (Ci) ($x10^7$)
I-131	2.7
I-132	4.0
I-133	5.5
I-134	6.1
I-135	5.2

a) Based on NRC Regulatory Guide 1.195 assumptions, half of the iodine activity released from the core to the containment is available for release to the outside atmosphere.

TABLE 6.5-7
ESF FILTRATION UNITS EMPLOYED DURING DESIGN BASIS ACCIDENTS

	Design Basis Accident	Filtration Units Employed	Reference Section
1.	Loss-of-coolant accident	Control Room Emergency pressurization units	15.6.5.4(4)(b)
		Emergency filtration units	15.6.5.4(4)(b)
		Primary plant exhaust unit	15.6.5.4(2)(f)
2.	Waste gas system failure	Control Room Emergency Pressurization Unit and Emergency Filtration Units	15.7.1
3.	Steam generator tube rupture	Control Room Emergency Pressurization Unit and Emergency Filtration Units	15.6.3
4.	Fuel handling accident	Control Room Emergency Pressurization Unit and Emergency Filtration Units	15.7.4
5.	Control rod ejection accident	Control Room Emergency Pressurization Unit and Emergency Filtration Units	15.4.8
6.	CVCS letdown line break	Control Room Emergency Pressurization Unit and Emergency Filtration Units	15.6.2
7.	Main Steam line	Control Room Emergency Pressurization Unit and Emergency Filtration Units	15.1.5
8.	Liquid waste tank failure	Control Room Emergency Pressurization Unit and Emergency Filtration Units	15.7.2
9.	Locked Rotor	Control Room Emergency Pressurization Unit and Emergency Filtration Units	15.3.3

6.6 INSERVICE INSPECTION OF ASME CODE CLASS 2 & 3 COMPONENTS

6.6.1 COMPONENTS SUBJECT TO EXAMINATION

Fluid system components for CPNPP that are important to nuclear safety have been classified by Luminant Power as Safety Class 1, 2, and 3 and correspond to the ASME Boiler and Pressure Vessel Code, Section III, Classes 1, 2, and 3. The inservice inspection (ISI) program for Class 1 components is contained in Section 5.2.4. Class 2 components and systems are examined in accordance with Table IWC-2500-1, of ASME Section XI. Class 3 components and systems are examined in accordance with Table IWD-2500-1 of ASME Section XI.

During the preservice inspection, Class 1, 2 and 3 systems were inspected to the 1980 Edition for Unit 1 and to the 1983 Edition with Code Case N-408 for Unit 2. Details of the preservice inspection, including relief requests, are included in the Preservice Inspection Plan for each unit.

The Inservice Inspection Program for Class 1, 2, and 3 systems and component supports is written to Subsections IWB, IWC, IWD, and IWF of ASME Section XI (Edition and Addenda as required by 10CFR 50.55a).

6.6.2 ACCESSIBILITY

Class 2 and 3 components and systems have been designed and arranged for accessibility to the extent practical in order to conduct the ISI program in accordance with Articles IWC-2000 and IWD-2000 at the frequency specified by Subarticles IWC-2400 and IWD-2400.

6.6.3 EXAMINATION TECHNIQUES AND PROCEDURES

Class 2 systems and components are inservice inspected by volumetric, surface and visual examination techniques to meet the requirements of Article IWC-2000, of ASME Section XI. Ultrasonic Techniques, are generally employed where volumetric examination is required, and either liquid penetrant or magnetic particle techniques are employed where surface examination is required. Visual examinations are conducted in accordance with the requirements of Subarticle IWA-2210, of ASME Section XI.

Class 3 systems and components are visually examined during system inservice tests, component functional tests, or system pressure tests to detect evidence of component leakage, structural distress of corrosion, in accordance with the requirements of Subarticle IWD-2600, of ASME Section XI. Visual inspection of integral attachments is performed in accordance with the requirements of Table IWD-2500-1, of ASME Section XI.

6.6.4 INSPECTIONS INTERVALS

An inspection schedule for Class 2 and 3 system components will be developed in accordance with guidelines of Subarticles IWC-2400 and IWD-2400, and IWF-2400, of ASME Section XI.

6.6.5 EXAMINATION CATEGORIES AND REQUIREMENTS

The examination categories and requirements will be in accordance with the guidelines of Table IWC-2500-1 to the extent practicable. The examination requirements for Class 3

components will be in accordance with the guidelines of Subarticle IWD-2600 to the extent practicable.

An inservice inspection program, which will discuss the examination categories, will be submitted within nine (9) months of the date of the operating license, in compliance with the requirements of 10 CFR Part 50 Section 50.55a, paragraph (g).

6.6.6 EVALUATION OF EXAMINATION RESULTS

Articles IWC-3000 and IWD-3000, concerning evaluation of examination results for class 2 and 3 components, have not yet been prepared. After publication, Articles IWC-3000 and IWD-3000 will be reviewed and incorporated in this section if found applicable.

Presently, Class 2 and 3 components will be evaluated in accordance with Article IWB-3000.

Components with unacceptable indications will be repaired or replaced in accordance with the guidelines of Articles IWC-4000 and IWD-4000, except if the guidelines of IWC-4000 & IWD-4000 are inappropriate for the components, then the guidelines of Article IWA-4000 will apply.

The above evaluation and repair programs conform to ASME Section XI.

6.6.7 SYSTEM PRESSURE TEST

Class 2 systems subject to system pressure tests will be tested in accordance with Articles IWA-5000 and IWC-5000 and Table IWC-2500-1, of ASME Section XI.

Class 3 systems subject to system pressure tests will be tested in accordance with the requirements of Articles IWA-5000, IWD-5000, and Table IWD-2500-1, of ASME Section XI.

6.6.8 AUGMENTED INSERVICE INSPECTION

Main Steam and main feedwater piping located in the containment penetration areas and designated "break exclusion piping" is subject to augmented inservice inspection in accordance with paragraph B.2.d of APCSB 3-1. 100 percent of all circumferential and longitudinal welds on this piping, except as may be exempted by ASME Code Section XI paragraph IWC-1220, is volumetrically inspected each 10 year inspection interval.

6.7 MAIN STEAM LINE ISOLATION VALVE LEAKAGE CONTROL SYSTEM

This section is not applicable to Comanche Peak Seam Electric Station.

7.0 INSTRUMENTATION AND CONTROLS

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7.1 INTRODUCTION

This chapter presents the various plant instrumentation and control systems by relating the functional performance requirements, design bases, system descriptions, design evaluations, and tests and inspections for each. The information provided in this chapter emphasizes those instruments and associated equipment which constitute the protection system as defined in the Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971, "IEEE Standard: Criteria for Protection Systems for Nuclear Power Generating Stations."

The primary purpose of the instrumentation and control systems is to provide automatic protection and exercise proper control against unsafe and improper reactor operation during steady state and transient power operations (American Nuclear Society (ANS) Conditions I, II and III) and to provide initiating signals to mitigate the consequences of faulted conditions (ANS Condition IV). ANS conditions are discussed in Chapter 15. Consequently, the information presented in this chapter emphasizes those instrumentation and control systems which are central to assuring that the reactor can be operated to produce power in a manner that ensures no undue risk to the health and safety of the public.

These systems meet the applicable criteria and codes, such as General Design Criteria and IEEE Standards, concerned with the safe generation of nuclear power. Table 7.1-1 lists applicable criteria and directs the reader to the sections where conformance is discussed. Tables 7.1-2.2 through 7.1-2.7 provide a matrix which identifies the systems to which the applicable criteria of Table 7.1-1 is applied.

Definitions

Terminology used in this chapter is based on the definitions given in IEEE Standard 279-1971. In addition, the following definitions apply:

1. Degree of redundancy

   The difference between the number of channels monitoring a variable and the number of channels which when tripped will cause an automatic system trip.

2. Minimum degree of redundancy

   The degree of redundancy below which operation is prohibited, or otherwise restricted by the Technical Specifications.

3. Cold shutdown condition

   When the reactor is subcritical by at least 1 percent k/k; percent rated thermal power, excluding decay heat, is zero; and T_{avg} is $\leq$ 200°F.

4. Hot shutdown condition

   When the reactor is subcritical by at least 1 percent k/k; percent rated thermal power, excluding decay heat, is zero; and 350°F > T_{avg} > 200°F.

5. Hot standby condition

When the reactor is subcritical by at least 1 percent k/k; percent rated thermal power, excluding decay heat, is zero; and $T_{avg} \geq 350°F$.

6. Phase A Containment Isolation

Closure of all nonessential process lines which penetrate the Containment, initiated by the safety injection signal. Phase A Containment isolation is on an “S” signal.

7. Phase B Containment Isolation

Closure of remaining process lines, initiated by Containment hi-3 pressure signal (process lines do not include engineered safety features lines). Phase B Containment isolation is on a “P” signal.

8. System response times

a. Reactor Trip System Response Time

The time delays are defined as the time required for a signal to reach the reactor trip breakers from the time the setpoint is reached following a step change in the variable being monitored from 5 percent below (or above) to 5 percent above (or below) the trip setpoint.

b. Engineered Safety Features Actuation System Response Time

The interval required for the engineered safety features sequence to be initiated subsequent to the point in time that the appropriate variable(s) exceed setpoints. The response time includes sensor/process (analog) and logic (digital) delay.

9. Reproducibility

This definition is taken from Scientific Apparatus Manufactures Association (SAMA) Standard PMC-20.2-1973, Process Measurement and Control Terminology: “the closeness of agreement among repeated measurements of the output for the same value of input, under normal operating conditions over a period of time, approaching from both directions.” It includes drift due to environmental effects, hysteresis, long term drift, and repeatability. Long term drift (aging of components, etc.) is not an important factor in accuracy requirements since, in general, the drift is not significant with respect to the time elapsed between testing. Therefore, long term drift may be eliminated from this definition. Reproducibility, in most cases, is a part of the definition of accuracy (see item 10).

10. Accuracy

This definition is derived from SAMA Standard PMC-20.1-1973, Process Measurement and Control Terminology. An accuracy statement for a device falls under note 2 of the SAMA definition of accuracy, which means reference accuracy or the accuracy of that device at reference operating conditions: “Reference accuracy includes conformity,

hysteresis and repeatability." To adequately define the accuracy of a system, the term reproducibility is useful as it covers normal operating conditions. The following terms, "trip accuracy" and "indicated accuracy" etc., will then include conformity and reproducibility under normal operating conditions. Where the final result does not have to conform to an actual process variable but is related to another value established by testing, conformity may be eliminated, and the term reproducibility may be substituted for accuracy.

11. Normal Operating Conditions

For this document, these conditions cover all normal process temperature and pressure changes. Also included are ambient temperature changes around the transmitter and racks. This document does not include any accuracies under "post-accident" conditions.

12. Readout Devices

For consistency the final device of a complete channel is considered a readout device. This includes indicators, recorders, isolators (nonadjustable), and controllers.

13. Channel Accuracy

This definition includes accuracy of primary element, transmitter and rack modules. It does not include readout devices or rack environmental effects, but does include process and environmental effects on field mounted hardware. Rack environmental effects are included in the next two definitions to avoid duplication due to dual inputs.

14. Indicated and/or Recorded Accuracy

This definition includes channel accuracy, accuracy of readout devices and rack environmental effects.

15. Trip Accuracy

This definition includes comparator accuracy, channel accuracy, each input, and rack environmental effects. This is the tolerance expressed in process terms (or percent of span) within which the complete channel must perform its intended trip function. This includes all instrument errors but no process effects such as streaming. The term "actuation accuracy" may be used where the word "trip" might cause confusion (for example, when starting pumps and other equipment).

16. Control Accuracy

This definition includes channel accuracy, accuracy of readout devices (isolator and controller), and rack environmental effects. Where an isolator separates control and protection signals, the isolator accuracy is added to the channel accuracy to determine control accuracy, but credit is taken for tuning beyond this point; i.e., the accuracy of these modules (excluding controllers) is included in the original channel accuracy. It is simply defined as the accuracy of the control signal in percent of the span of that signal. This will then include gain changes where the control span is different from the span of the measured variable. Where controllers are involved, the control span is the input span

of the controller. No error is included for the time in which the system is in a nonsteady state condition.

7.1.1 IDENTIFICATION OF SAFETY-RELATED SYSTEMS

7.1.1.1 Safety-Related Systems

The Nuclear Steam Supply System (NSSS) and the balance of plant (BOP) instrumentation discussed in Chapter 7 that is required to function to achieve the system responses assumed in the safety evaluations, and those needed to shutdown the plant safely are given in this section.

Refer to Figure 7.1-3 for location layout drawings of Class 1E instrumentation. These figures pertain to location layout drawing requirements as discussed in Sections 7.2, 7.3 and 7.5.

7.1.1.1.1 Reactor Trip System

The Reactor Trip System (RTS) is a functionally defined system described in Section 7.2. The RTS responsibility falls primarily under the NSSS supplier, with the exceptions of underfrequency, and undervoltage, and turbine trip signal which are under BOP scope (See Figure 7.2-1). The equipment which provides the trip functions is identified and discussed in Section 7.2. Design bases for the RTS are given in Section 7.1.2.1. Figure 7.1-1 is a block diagram of this system.

7.1.1.1.2 Engineered Safety Features Actuation System

The Engineered Safety Features Actuation System (ESFAS) is a functionally defined system described in Section 7.3. The equipment which provides the actuation functions is identified and discussed in Section 7.3. Design bases for the ESFAS are given in Section 7.1.2.1.

The ESF and ESF Support Systems requiring actuation are as follows:

ESF Systems:

1. Emergency Core Cooling System (Section 6.3)

   a. Safety Injection System

   b. Residual Heat Removal System (partial)

   c. Chemical and Volume Control System (partial)

   Designed by NSSS vendor.

2. Containment Spray System (Section 6.2.2)

   a. Containment Spray Chemical Additive Subsystem (Section 6.5.2)

   Designed under the Architect-Engineer's (A-E) specifications.

3. Containment Isolation System (Section 6.2.4)

   Containment isolation valves for the following systems are furnished by the NSSS vendor.

   a. Chemical and Volume Control System.

   b. Residual Heat Removal System.

   c. Safety Injection System.

   d. Waste Processing System.

   The remaining Containment isolation valves are built to the specifications of the A-E.

4. Deleted.

5. Control Room Air Conditioning System (Sections 6.4 and 9.4).

   Designed and built to the specifications of the A-E.

6. Auxiliary Feedwater System (Section 10.4.9).

   Designed and built to the specifications of the A-E.

7. ESF Filter Systems (Section 6.5)

   a. Control Room Air Conditioning System (partial)

   b. Primary Ventilation System (partial)

   Designed and built to the specification of A-E.

ESF Support System:

1. Component Cooling Water System (Section 9.2.2)

   Designed and built to the specifications of the A-E.

2. Service Water System (Section 9.2.1)

   Designed and built to the specifications of the A-E.

3. Onsite Power Supply System

   a. Diesel Generator Sets (Section 8.3)

   b. Diesel Generator F.O. Storage and Transfer System (Section 9.5.4)

   c. Diesel Generator Cooling Water System (Section 9.5.5)

d. Diesel Generator Starting System (Section 9.5.6)

e. Diesel Generator Lube Oil System (Section 9.5.7)

f. Diesel Generator Combustion Air Intake and Exhaust System (Section 9.5.8)

g. Diesel Generator Ventilation System (Section 9.4C)

h. D.C. System (Section 8.3.2)

Designed and built to the specifications of the A-E.

4. ESF Ventilation System (Section 9.4.5)

Designed and built to the specification of the A-E.

5. Safety Chilled Water System (Section 9.4F)

Designed and built to the specifications of the A-E.

6. Service Water Intake Structure Ventilation System (Section 9.4B)

Designed and built to the specifications of the A-E.

7. UPS Ventilation System (Section 9.4C.8)

Designed and built to the specifications of the A-E.

7.1.1.1.3 Class 1E 118V AC Uninterruptible Power System

Design bases for the Class 1E 118V AC Uninterruptible Power System (UPS) are given in Section 7.1.2.1. Further description of this system is provided in Section 7.6.1. The UPS for the reactor protection system is described in the above mentioned sections. For the Class 1E Static Uninterruptible Power System for the Balance of Plant furnished safety-related instrumentation refer to Section 8.3.1.

7.1.1.2 Safety-Related Display Instrumentation

Display instrumentation provides the operator with information to enable him to monitor the results of engineered safety features actions following a Condition II, III, or IV event. Section 7.5 (Table 7.5-7A, B & C) provides information required to maintain the plant in a hot shutdown condition, or to proceed to cold shutdown.

7.1.1.3 Instrumentation and Control System Designers

All systems discussed in Chapter 7 have definitive functional requirements developed on the basis of the Westinghouse NSSS design. Figure 7.2-1 defines scope interface. Regardless of the supplier, the functional requirements necessary to assure plant safety and proper control are clearly delineated.

7.1.1.4 Plant Comparison

System functions for all NSSS systems discussed in Chapter 7 are similar to those of the William B. McGuire Nuclear Station (Docket No. 50-369 and 50-370). A plant comparison table is provided in Section 1.3.

7.1.2 IDENTIFICATION OF SAFETY CRITERIA

Section 7.1.2.1 gives design bases for the systems given in Section 7.1.1.1. Design bases for nonsafety-related systems are provided in the sections which describe the systems. Conservative considerations for instrument errors are included in the accident analyses presented in Chapter 15. Functional requirements, developed on the basis of the results of the accident analyses, which have utilized conservative assumptions and parameters, are used in designing these systems and a preoperational testing program verifies the adequacy of the design. Accuracies are given in Table 7.2-3, and Section 7.3.1.2.6.

The documents listed in Table 7.1-1 were considered in the design of the systems given in Section 7.1.1. In general, the scope of these documents is given in the document itself. This determines the systems or parts of systems to which the document is applicable. A discussion of compliance with each document for systems in its scope is provided in the referenced sections given in Table 7.1-1 for each criterion. A matrix which identifies the systems to which the applicable criteria of Table 7.1-1 is applied is given in Tables 7.1-2.2 through 7.1-2.7. Because some documents were issued after design and testing had been completed, the equipment documentation may not meet the format requirements of some standards. Justification for any exceptions taken to each document for systems in its scope is provided in the referenced sections.

7.1.2.1 Design Bases

7.1.2.1.1 Reactor Trip System

The RTS acts to limit the consequences of Condition II events (faults of moderate frequency), such as loss of feedwater flow, by, at most, a shutdown of the reactor and turbine, with the plant capable of returning to operation after corrective action. The RTS features impose a limiting boundary region to plant operation which ensures that the reactor safety limits are not exceeded during Condition II events and that these events can be accommodated without developing into more severe conditions. Reactor trip setpoints will be provided in the Technical Specifications.

The design requirements for the RTS are derived by analyses of plant operating and fault conditions where automatic rapid control rod insertion is necessary in order to prevent or limit core or reactor coolant boundary damage. The design bases addressed in IEEE Standard 279-1971 are discussed in Section 7.2.1. The design limits specified by Westinghouse for the RTS are:

1. Minimum departure from nucleate boiling ratio (DNBR) shall not be less than the limit value as a result of any anticipated transient or malfunction (Condition II events).

2. Power density shall not exceed the rated linear power density for Condition II events.

3. The stress limit of the Reactor Coolant System for the various conditions shall be as specified in Sections 5.2, 5.3 and 5.4.

4. Release of radioactive material shall not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius as a result of any Condition III event.

5. For any Condition IV event, release of radioactive material shall not result in an undue risk to public health and safety.

7.1.2.1.2 Engineered Safety Features Actuation System

The ESFAS acts to limit the consequences of Condition III events (infrequent faults such as primary coolant spillage from a small rupture which exceeds normal charging system makeup and requires actuation of the Safety Injection System). The ESFAS acts to mitigate Condition IV events (limiting faults, which include the potential for significant release of radioactive material).

The design bases for the ESFAS are derived from the design bases given in Chapter 6 for the engineered safety features. Design bases requirements of IEEE Standard 279-1971 are addressed in Section 7.3.1.2. General design requirements are given below.

1. Automatic actuation requirements

   The primary requirement of the ESFAS is to receive input signals (information) from the various on-going processes within the reactor plant and Containment and automatically provide, as output, timely and effective signals to actuate the various components and subsystems comprising the Engineered Safety Features System.

2. Manual actuation requirements

   The ESFAS must have provisions in the Control Room for manually initiating the functions of the Engineered Safety Features System.

7.1.2.1.3 Class 1E 118V AC Uninterruptible Power System

The UPS provides continuous, reliable, regulated single phase alternating current (AC) power to all Reactor Protection System instrumentation and control equipment required for plant safety. Details of this system are provided in Section 7.6. The design bases are given below:

1. The inverter shall have the capacity and regulation required for the AC output for proper operation of the equipment supplied.

2. Redundant loads shall be assigned to different distribution panels which are supplied from different inverters.

3. Auxiliary devices that are required to operate dependent equipment shall be supplied from the same distribution panel to prevent the loss of electric power in one protection set from causing the loss of equipment in another protection set. No single failure shall cause a loss of power supply to more than one distribution panel.

4. Each of the distribution panels shall have access only to its respective inverter supply and a standby power supply.

5. The system shall comply with IEEE Standard 308-1974 Section 5.4.

7.1.2.1.4 Class 1E Onsite AC Power System

Design bases and system description for the Emergency Power Supply System is provided in Section 8.3.

7.1.2.1.5 Interlocks

Interlocks are discussed in Sections 7.2, 7.3, 7.6 and 7.7. The protection (P) interlocks are given in Tables 7.2-2 and 7.3-3. The safety analyses demonstrate that even under conservative critical conditions for either postulated or hypothetical accidents, the protective systems ensure that the NSSS will be put into and maintained in a safe state following an ANS Condition II, III or IV event commensurate with applicable Technical Specifications and pertinent ANS Criteria. Therefore the protective systems have been designed to meet IEEE Standard 279-1971 and are entirely redundant and separate, including all permissives and blocks. All blocks of a protective function are automatically cleared whenever the protective function would be required to function in accordance with General Design Criteria 20, 21 and 22 and Sections 4.11, 4.12 and 4.13 of IEEE Standard 279-1971. Control interlocks (C) are identified on Table 7.7-1. Because control interlocks are not safety-related, they have not been specifically designed to meet the requirements of IEEE 279 protection system standards.

7.1.2.1.6 Bypasses

Bypasses are designed to meet the requirements of IEEE Standard 279-1971, Sections 4.11, 4.12, 4.13 and 4.14. A discussion of bypasses provided is given in Sections 7.2 and 7.3.

The capability of bypass testing is provided for the 7300 Process Protection System Reactor Trip and Engineered Safety Features Actuation functions and the Nuclear Instrumentation System Reactor Trip functions.

The Bypass Test Instrumentation which allows testing in a bypassed condition instead of a tripped condition conforms to applicable regulatory criteria including IEEE 279-1971 and Regulatory Guide 1.47 as well as prior regulatory guidance concerning test in bypass. Additional information concerning test in bypass can be found in WCAP-14096.

7.1.2.1.7 Equipment Protection

The criteria for equipment protection are given in Chapter 3. Equipment related to safe operation of the plant is designed, constructed and installed to protect it from damage. This is accomplished by working to accepted standards and criteria aimed at providing reliable instrumentation which is available under varying conditions. As an example, equipment is seismically qualified in accordance with the discussion in Chapter 3. Independence and separation is achieved, as required by IEEE Standard 279-1971, IEEE Standard 384-1974 and Regulatory Guide 1.75, either by barriers, physical separation or demonstration test. This serves to protect against complete destruction of a system by fires, missiles or other natural hazards.

7.1.2.1.8 Diversity

Functional diversity has been designed into the system. Functional diversity is discussed in Reference [1]. The extent of diverse system variables has been evaluated for a wide variety of postulated accidents. Generally, two or more diverse protection functions would automatically terminate an accident before unacceptable consequences could occur.

For example, there are automatic reactor trips based upon neutron flux measurements, reactor coolant loop flow measurements, reactor coolant loop hot leg N-16 measurements pressurizer pressure and level measurements, and reactor coolant pump underfrequency and undervoltage measurements, as well as manually, and by initiation of a safety injection signal.

Regarding the ESFAS for a loss of coolant accident, a safety injection signal can be obtained manually or by automatic initiation from two diverse parameter measurements.

1. Low pressurizer pressure.

2. High Containment pressure (hi-1).

For a steam line break accident, safety injection signal actuation is provided by:

1. Low compensated steamline pressure.

2. For a steam line break inside Containment, high Containment pressure (hi-1) provides an additional parameter for generation of the signal.

All of the above sets of signals are redundant and physically separated and meet the requirements of IEEE Standard 279-1971.

7.1.2.1.9 Bistable Trip Setpoints

The setpoint methodology is basically the square root of the sum of the squares (SRSS) of the statistically independent parameters. Dependent parameters are arithmetically summed prior to systematic combination with other terms. The total combination of error terms is identified as the channel statistical allowance (CSA).

Three values applicable to reactor trip and engineered safety features actuation are specified:

1. Safety Analysis limit

2. Nominal Safety System Setting

3. Limiting Safety System Setting

The safety analysis limit is the value assumed in the accident analysis and is the least conservative value.

The nominal safety system setting is the technical specification “Trip Setpoint” and is determined by subtracting the channel’s “total allowance” (Total Allowance = CSA + Margin) from the safety analysis limit.

The limiting safety system setting is the technical specification “allowable value” and a setpoint exceeding this value indicates that a channel may be inoperable. The allowable value is determined by either adding the arithmetic sum of the error components encountered during periodic surveillances (including drift) to the nominal safety system setting or by subtracting the sum of margin plus a statistical combination of channel error terms except those encountered during periodic surveillances from the safety analysis limit. The most conservative result is used as the allowable value.

The trip setpoint is determined by factors other than the most accurate portion of the instrument’s range. The safety analysis limit setpoint is determined only by the accident analysis. As described above, allowance is then made for process uncertainties, instrument error, instrument drift, and calibration uncertainty to obtain the nominal setpoint value which is actually set into the equipment. The only requirement on the instrument’s accuracy value is that over the instrument span, the error must always be less than or equal to the error value allowed in the accident analysis. The instrument does not need to be the most accurate at the setpoint value as long as it meets the minimum accuracy requirement. The accident analysis accounts for the expected errors at the actual setpoint.

Range selection for the instrumentation covers the expected range of the process variable being monitored consistent with its application. The design of the reactor protection and engineered safety features systems is such that the bistable trip setpoints do not require process transmitters to operate within 5 percent of the high and low end of their calibrated span or range. Functional requirements established for every channel in the reactor protection and engineered safety features systems stipulate the maximum allowable errors on accuracy, linearity, and reproducibility. The protection channels have the capability for, and are tested to ascertain that the characteristics throughout the entire span in all aspects are acceptable and meets functional requirement specifications. As a result, no protection channel operates normally within 5 percent of the limits of its specified span.

In this regard, it should be noted that the specific functional requirements for response time, setpoint, and operating span is finalized based on the plant specific safety studies. Emphasis is placed on establishing adequate performance requirements under both normal and faulted conditions. This includes consideration of process transmitters margins such that even under a highly improbable situation of full power operation at the limits of the operating map (as defined by the high and low pressure reactor trip, N-16 Overpower and Overtemperature trip lines (DNB protection) and the steam generator safety valve pressure setpoint) that adequate instrument response is available to ensure plant safety.

7.1.2.1.10 Engineered Safety Features Motor Specifications

The minimum voltage for the residual heat removal pump motor and Engineered Safety Features Auxiliary System pump motors rated 6600 volt and 460 volt is 80 percent of rated voltage at the motor terminals to start and accelerate the driven equipment. The motors are capable of accelerating the driven equipment from rest to operating speed within 5 seconds.

The minimum margin of motor torque over the pump full load torque (as defined by the pump speed/torque curve) will be sufficient to accelerate all the driven equipment within 5 seconds and with 80 percent of rated voltage at the motor terminals from standstill to operating speed.

Verification of the engineered safety features pump motors capability to operate within design temperature ratings, including the NEMA Test Specification MG1-20.43 (“number of starts”), is based on the design tests of the prototype motor that are performed at the manufacturer’s test facilities, rather than by means of initial or periodic tests in the field.

For conditions where the motor stalls or fails to start, the influence of these conditions is best monitored from the current versus time characteristics, and equipment protection for this is provided by the circuit breaker trip function.

7.1.2.2 Independence of Redundant Safety-Related Systems

The safety-related systems in Section 7.1.1.1 are designed to meet the independence and separation requirements of Criterion 22 of the 1971 General Design Criteria and Section 4.6 of IEEE Standard 279-1971.

The electrical power supply, instrumentation, and control wiring for redundant circuits of a nuclear plant have physical separation to preserve the redundancy and to ensure that no single credible event will prevent operation of the associated function due to electrical conductor damage. Critical circuits and functions include power, control and analog instrumentation associated with the operation of the RTS or ESFAS. Credible events shall include, but not be limited to, the effects of short circuits, pipe rupture, missiles, fire, etc. and are considered in the basic plant design. Control board details are given in Section 7.7.1.12. In the control board, separation of redundant circuits is maintained as described in Section 8.3.1.4.

7.1.2.2.1 General

The criteria for the installation and routing of cables is discussed in Section 8.3.1.4.

The physical separation criteria for redundant safety-related system sensors, sensing lines, wireways, cables, and components on racks within Westinghouse NSSS scope meet recommendations [2] contained in Regulatory Guide 1.75 with the following comments:

1. The Westinghouse design of the protection system does not rely on over-current devices to prevent malfunctions in one circuit from causing unacceptable influences on the functioning of the protection system [2]. The protection system uses redundant instrumentation channels and actuation trains and incorporates physical and electrical separation to prevent faults in one channel from degrading any other protection channel.

   Within a protection system, however, the Westinghouse design does rely on over-current devices as isolation devices to prevent malfunctions in Non-Class 1E portions of a circuit from causing unacceptable influences on the Class 1E function of the circuit [4].

   For discussion on control grade instrumentation power circuits powered from protection grade power supplies, see paragraph 8.3.1.2.1, item 7 “Compliance with NRC Regulatory Guide 1.75 [5] and IEEE 384 [6]”.

2. Separation recommendations for redundant instrumentation racks are not the same as those given in Regulatory Position C.16 of Regulatory Guide 1.75, Revision 1, for the control boards because of different functional requirements. Main control boards contain redundant circuits which are required to be physically separated from each other.

However, since there are no redundant circuits which share a single compartment of an NSSS protection instrumentation rack, and since these redundant protection instrumentation racks are physically separated from each other, the physical separation requirements specified for the main control board do not apply.

However, redundant, isolated control signal cables leaving the protection racks are brought into close proximity elsewhere in the plant, such as the control board. It could be postulated that electrical faults, or interference, at these locations might be propagated into all redundant racks and degrade protection circuits because of the close proximity of protection and control wiring within each rack. Regulatory Guide 1.75 (Regulatory Position C.4) and IEEE Standard 384-1974 (Section 4.5(3)) provide the option to demonstrate that the absence of physical separation could not significantly reduce the availability of Class 1E circuits.

The Nuclear Instrumentation System and Solid State Protection System were included in the "Westinghouse Protection System Noise Tests" report submitted and accepted by the Nuclear Regulatory Commission (NRC) in support of the Diablo Canyon application (Docket No. 50-275 and 50-323). The tests on the Process Control System - 7300 Series are reported in Reference [2], the conclusions having been accepted by the NRC.

The protection and surveillance upgrade package cabinets that house the protection equipment and components including isolators are 7300 series process control equipment similar to that reported in Reference [2].

Provisions are made to provide assurance that maximum credible fault voltages and conditions which could be postulated in the Comanche Peak Nuclear Power Plant (CPNPP), as a result of BOP cable routing design, will not exceed those used in the tests.

These Westinghouse tests demonstrated that protection systems performance would not be degraded even if subjected to abnormal electrical conditions which far exceed those which can be reasonably postulated.

The Auxiliary Relay Racks, Safeguards Test Cabinets, and Reactor Trip Switchgear utilize Class 1E relays to provide isolation between redundant Class 1E circuits and between Class 1E/non Class 1E circuits. Refer to FSAR Sec. 8.3.1.2.1.7 item b(1). This equipment implements similar wiring practices and layout as implemented for the 7300 series process control system cabinets supplied by Westinghouse. The 7300 series process control system noise test (WCAP-8892A) demonstrated that a fault will not propagate wire to wire even if the wires are in close proximity (i.e., touching). Separate auxiliary relay racks are utilized for redundant trains further ensuring integrity of divisional circuits. For the Reactor Trip Switchgear, the additional concern of an accidental short between the coil and contact terminals of the cross train interlock relays was evaluated with the conclusion that the ability of the breakers to perform their trip function is not impacted. Therefore, internal separation of the wiring internal to these cabinets is not required.

3. The physical separation criteria for instrument cabinets (including the protection and surveillance upgrade package cabinets) within Westinghouse NSSS scope meet the recommendations contained in Section 5.7 of IEEE Standard 384-1974.

4. The BOP Analog Instrumentation System utilizes redundant safety trains and incorporates physical and electrical separation to prevent faults in one safety train from degrading any other safety train. Each BOP Analog Rack cabinet contains only single safety related train wiring and devices and therefore the separation requirement (between trains) is not applicable in this case.

   The train orientation and wiring techniques used in the 7300 series process control system has been demonstrated by tests to meet regulatory requirements per Regulatory Guide 1.75 (Ref. WCAP-8892-A, "Westinghouse 7300 Series Process System Noise Tests," June 1977). In the BOP Analog Instrumentation System, Westinghouse utilized similar wiring techniques. Westinghouse certificate of qualification, CQ-W9525, establishes an auditable link between hardware furnished under the BOP Analog Instrumentation System and the 7300 Series Process Control Equipment. Additionally it has been demonstrated that close proximity of safety train wiring to non-safety train wiring within individual BOP Analog Instrumentation cabinets will not degrade the safety functions of Class 1E circuits should faults occur in the non-safety train circuits.

   Therefore, the physical and electrical separation criteria for the BOP Analog Instrumentation System supplied by Westinghouse meet the recommendations contained in Regulatory Guide 1.75.

7.1.2.2.2 Specific Systems

Independence is maintained throughout the system, extending from the sensor through to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs and Containment penetrations for each redundant protection channel set. Redundant analog equipment is separated by locating modules in different protection rack sets. Each redundant channel set is energized from a separate AC power feed.

There are four separate process analog sets. Separation of redundant analog channels begins at the process sensors and is maintained in the field wiring, Containment penetrations and analog protection cabinets to the redundant trains in the logic racks. Redundant analog channels are separated by locating modules in different protection cabinets. Since all equipment within any cabinet is associated with a single protection set, there is no requirement for separation of wiring and components within the cabinet.

Two three-bay cabinets housing the protection and surveillance upgrade functions involving the N-16 Power Measuring System are included in process instrumentation and control system. Each of the two three-bay cabinets contains equipment for two protection sets with appropriate physical and electrical separation and provisions for top and/or bottom entry of the cables. One of the three-bay cabinets contains the surveillance instrumentation (in its center bay which has been abandoned in place) with the appropriate separation provided. Contained in each protection set is instrumentation to perform the N-16 power calculation utilizing a T_{cold} input from process protection and N-16 detector signals from two hot leg detectors. In addition, the four section neutron power range detector signals are brought into the protection racks, summed (to form Q_{UPPER} and Q_{LOWER}), and sent to Nuclear Instrumentation System (NIS) rack (see Figure 7.1-2).

In the Nuclear Instrumentation System, Process Systems, and the Solid State Protection System input cabinets where redundant channel instrumentation is physically adjacent, there are no wireways, or cable penetrations which would permit, for example, a fire resulting from electrical failure in one channel to propagate into redundant channels in the logic racks. Redundant analog channels are separated by locating modules in different cabinets. Since all equipment within any cabinet is associated with a single protection set, there is no requirement for separation of wiring and components within the protection cabinet.

Two reactor trip breakers are actuated by two separate logic matrices which interrupt power to the control rod drive mechanisms. The breaker main contacts are connected in series with the power supply so that opening either breaker interrupts power to all full length control rod drive mechanisms, permitting the rods to free fall into the core.

1. Reactor Trip System

   a. Separate routing shall be maintained for the four basic RTS channel sets analog sensing signals, bistable output signals and power supplies for such systems. The separation of these four channel sets shall be maintained from sensors to instrument cabinets to logic system input cabinets.

   b. Separate routing of the redundant reactor trip signals from the redundant logic system cabinets shall be maintained, and in addition, they shall be separated (by spatial separation or by provision of barriers or by separate cable trays or wireways) from the four analog channel sets.

2. Engineered Safety Features Actuation System

   a. Separate routing shall be maintained for the four basic sets of ESFAS analog sensing signals, bistable output signals and power supplies for such systems. The separation of these four channel sets shall be maintained from sensors to instrument cabinets to logic system input cabinets.

   b. Separate routing of the engineered safety features actuation signals from the redundant logic system cabinets shall be maintained. In addition, they shall be separated by spatial separation or by provisions of barriers or by separate cable trays or wireways from the four analog channel sets.

   c. Separate routing of control and power circuits associated with the operation of engineered safety features equipment is required to retain redundancies provided in the system design and power supplies.

3. Class 1E Static Uninterruptible Power System

   The separation criteria presented also apply to the power supplies for the load centers and buses distributing power to redundant components and to the control of these power supplies.

The RTS and ESFAS analog and digital circuits may be routed in the same wireways provided circuits have the same power supply and channel set identified (I, II, III or IV).

7.1.2.2.3 Fire Protection

For the electrical equipment it has been specified that noncombustible or fire retardant materials be used. Specification requirements ensure that materials will not be used which may ignite or explode from an electrical spark, flame, or from overheating, or will independently support combustion. These reviews also have included assurance of conservative current carrying capacities of all instrument cabinet wiring, which precludes electrical fires resulting from excessive overcurrent (I^2R) losses. For example, wiring used for instrument cabinet construction for the NSSS has teflon or tefzel insulation and is adequately sized based on current carrying capacities set forth by the National Electric Code. Braided sheathed material is noncombustible. The cables in power trays are sized using derating factors listed in IPCEA Publications P-46-426 and P-54-440.

For early warning protection against propagation of electrical fires, smoke or other high sensitivity detectors are provided for fire detection and alarm in remote wireways or other unattended areas where large concentrations of cables are installed. Refer to Section 8.3.3.

Details of the Fire Protection System are provided in Section 9.5.1.

7.1.2.3 Physical Identification of Safety-Related Equipment

There are four separate protection sets identifiable with process equipment associated with the RTS and ESFAS. A protection set may be comprised of more than a single process equipment cabinet. The color coding of each process equipment rack nameplate coincides with the color code established for the protection set of which it is a part. Redundant channels are separated by locating them in different equipment cabinets. Separation of redundant channels begins at the process sensors and is maintained in the field wiring, Containment penetrations and equipment cabinets to the redundant trains in the logic racks. The Solid State Protection System input cabinets are divided into four isolated compartments, each serving one of the four redundant input channels. Horizontal 1/8 inch thick solid steel barriers, coated with fire retardant paint, separate the compartments. Four, 1/8 inch thick solid steel, wireways coated with fire retardant paint enter the input cabinets vertically, even in its own quadrant. The wireway for a particular compartment is open only into that compartment so that flame could not propagate to affect other channels. At the logic racks the protection set color coding for redundant channels is clearly maintained until the channel loses its identity in the redundant logic trains. The color coded nameplates described below provide identification of equipment associated with protective functions and their channel set association:

Protection Set	Color Coding
I	RED with WHITE lettering
II	WHITE with BLACK lettering
III	BLUE with WHITE lettering
IV	YELLOW with BLACK lettering

All non-cabinet mounted protective equipment and components are provided with an identification tag or nameplate. Small electrical components such as relays have nameplates on

the enclosure which houses them. All cables are numbered with identification tags. In congested areas, such as under or over the control boards, instrument racks, etc., cable trays and conduits containing redundant circuits shall be identified using permanent markings. The purpose of such markings is to facilitate cable routing identification for future modification or additions. Positive permanent identification of cables and/or conductors shall be made at all terminal points. There are also identification nameplates on the input panels of the Solid State Logic Protection System.

7.1.2.4 Conformance to Criteria

A listing of applicable criteria and the sections where conformance is discussed is given in Table 7.1-1. A matrix of the applicability of this criteria to instrumentation and control systems is provided in Tables 7.1-2.2 through 7.1-2.7.

7.1.2.5 Conformance to Regulatory Guide 1.22

Periodic testing of the RTS and ESFAS, as described in Sections 7.2.2 and 7.3.2, complies with Regulatory Guide 1.22, “Periodic Testing of Protection System Actuation Functions.”

Where the ability of a system to respond to a bona fide accident signal is intentionally bypassed from the safeguards test cabinet for the purpose of performing a test during reactor operation, each bypass condition is automatically indicated to the reactor operator in the main Control Room by a separate annunciator for the train in test. Test circuitry does not allow two trains of the SSPS to be tested at the same time so that extension of the bypass condition to the redundant system is prevented. Administrative and procedural control are used to prevent testing of more than one protection set of the analog circuitry simultaneously. For those devices without additional test circuits that will be manually disabled to prevent operation, the above indication will be manually initiated prior to disabling.

The actuation logic for the RTS and ESFAS is tested as described in Sections 7.2 and 7.3. As recommended by Regulatory Guide 1.22, where actuated equipment is not tested during reactor operation, it has been determined that:

1. There is no practicable system design that would permit operation of the equipment without adversely affecting the safety or operability of the plant;

2. The probability that the protection system will fail to initiate the operation of the equipment is, and can be maintained, acceptably low without testing the equipment during reactor operation; and

3. The equipment can routinely be tested when the reactor is shutdown.

The list of equipment that cannot be tested at full power so as not to damage equipment or upset plant operation is:

1. Manual actuation switches.

2. Reactor coolant pump breakers.

3. Turbine trip equipment from reactor trip.

4. Main steam line isolation valves (close).

5. Main feedwater isolation valves (close).

6. Main feedwater control valves (close).

7. Reactor coolant pump component cooling water supply and return isolation valves (close).

8. Reactor coolant pump seal water return isolation valves (close).

9. Unit 2 Feedwater splitflow bypass valves (close).

10. Feedwater isolation bypass Valves (close).

11. Unit 2 Feedwater preheater bypass valves (close).

12. Feedwater control bypass valves (close).

13. Chilled water supply and return header to chilled water recirculation pump isolation valves (close).

14. Instrument air to containment isolation valve (close).

15. Ventilation chiller CCW supply and discharge control valves (close).

16. Intentionally blank.

17. Generator trip on turbine trip.

18. Residual Heat Removal Pump containment sump suction isolation valve (close).

19. Normal charging containment isolation valves (close).

20. Normal letdown containment isolation valves (close).

21. RWST - charging pump suction isolation valves (close).

22. VCT outlet isolation valves (close).

23. High head safety injection isolation valves (open).

24. Selected valves from Inservice Testing Plan.

The justifications for not testing the above 24 items at full power are discussed below.

1. Manual actuation switches

These would cause initiation of their protection system function at power causing plant upset and/or reactor trip. It should be noted that the reactor trip function that is derived from the automatic safety injection signal is tested at power as follows:

a. The analog signals, from which the automatic safety injection signal is derived, is tested at power in the same manner as the other analog signals and as described in Section 7.2.2.2.3.(10). The processing of these signals in the Solid State Protection System wherein their channel orientation converts to a logic train orientation is tested at power by the built-in semiautomatic test provisions of the Solid State Protection System. The reactor trip breakers are tested at power as discussed in Section 7.2.2.2.3.(10).

2. Tripping of reactor coolant pump breakers

No credit is taken in the accident analyses for a reactor coolant pump breaker opening causing a direct reactor trip. Since testing them at power would cause plant upset, the reactor coolant pump breakers do not need to be tested at power.

3. Turbine

The generation of a turbine trip on demand from the RTS is not fully testable at power. Testing of the Turbine Trip Block (hydraulic 2 out of 3 logic) is not practical at power, since partial or complete exercising will cause a turbine trip. The Turbine Trip Block solenoid valves and associated hydraulic pistons are individually tested at power. In addition, the Turbine Trip Black is functionally tested during each startup.

4. Closing the main steam line isolation valves

Main steam isolation valves are full stroke tested during refueling outages in accordance with the IST Plan. Testing of the main steam isolation valves to closure at power is not practical. As the plant power is increased, the core average temperature is programmed to increase. If the valves are closed under these elevated temperature conditions, the steam pressure transient would unnecessarily operate the steam generator relief valves and possibly the steam generator safety valves. The steam pressure transient produced would cause shrinkage in the steam generator level, which would cause the reactor to trip on low-low steam generator water level.

The valves are capable of being periodically partial stroke tested. Each valve can be actuated at slow speed and is limited to approximately 10 percent of full travel.

Based on the above identified problems incurred with full stroke periodic testing of the main steam line isolation valves at power and since 1) no practical system design will permit operation of the valves without adversely affecting the safety or operability of the plant, 2) the probability that the Protection System will fail to initiate the actuated equipment is acceptably low due to test up to final actuation, and 3) these valves will be tested during refueling outages in accordance with the IST plan, the proposed resolution meets the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22.

5. Closing the main feedwater isolation valves

The feedwater isolation valves are tested during refueling outages in accordance with the IST Plan. Periodic testing of the closure of these isolation valves at full power would induce steam generator water level transients and oscillations which would lead to a reactor trip. The operational status of these isolation valves is periodically verified in order to provide assurance of valve/valve actuator operability. The valves are capable of partial stroke tests limited to approximately 10 percent of valve stroke.

Since, 1) no practical system design will permit operation of these valves without adversely affecting the safety or operability of the plant, 2) the probability that the Protection System will fail to initiate the activated equipment is acceptably low due to testing up to final actuation and 3) these valves will be tested during refueling outages in accordance with the IST Plan, the proposed resolution meets the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22.

6. Closing the main feedwater control valves

These valves are routinely tested during refueling outages. To close them at power would adversely affect the operability of the plant. The verification of operability of feedwater control valves at power is assured by confirmation of proper operation of the steam generator water level system. The actual actuation function of the solenoids, which provides the closing function, is periodically tested at power as discussed in Section 7.3.2.2.5. The operability of the slave relay which actuates the solenoid, which is the actuating device, is verified during this test. Although the actual closing of these control valves is blocked when the slave relay is tested, all functions are tested to assure that no electrical malfunctions have occurred which could defeat the protective function. It is noted that the solenoids work on the de-energize-to-actuate principle, so that the feedwater control valves will fail close upon either the loss of electrical power to the solenoids or loss of air pressure.

Based on the above, the testing of the isolating function of feedwater control valves meets the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22.

7. Reactor coolant pump component cooling water supply and return isolation valves (close)

Component cooling water supply and return Containment isolation valves and component cooling water Non-Safeguard Loop isolation valves are routinely tested during refueling outages. Testing of these valves while the reactor coolant pumps are operating introduces an unnecessary risk of costly damage to all the reactor coolant pumps. Loss of component cooling water to these pumps is of economic consideration only, as the reactor coolant pumps are not required to perform any safety-related function.

The reactor coolant pumps will not seize due to complete loss of component cooling. Information from the pump manufacturer indicates that the bearing babbitt would eventually break down but not so rapidly as to overcome the inertia of the flywheel. If the pumps are not stopped within 3 to 10 minutes after component cooling water is isolated, pump damage could be incurred.

Additional Containment penetrations and Containment isolation valves would introduce additional unnecessary potential pathways for radioactive leakage following a postulated accident. Also, since the component cooling water flow rates and temperatures are about

equal during both plant power operation and plant refueling, periodic tests of these valves during a refueling outage would duplicate accident conditions. Additionally, possibility of failure of Containment isolation is remote because an additional failure of the low pressure fluid system in addition to failure of both isolation valves would have to occur to open a path through the Containment.

The Non-Safeguard Loop isolation valves provide reactor coolant pump cooling in series with the containment isolation valves and the considerations above are also applicable to them.

Based on the above described potential reactor coolant pump damage incurred with periodic testing of the subject component cooling water isolation valves at power, the duplication of at-power operating conditions during refueling outages, and since 1) no practical system design will permit operation of these valves without adversely affecting the safety or operability of the plant, 2) the probability that the Protection System will fail to initiate the activated equipment is acceptably low due to testing up to final actuation, and 3) these valves will be routinely tested during refueling outages when the reactor coolant pumps are not operating, the proposed resolution meets the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22.

8. Reactor coolant pump seal water return isolation valves (close)

Seal return line isolation valves are routinely tested during refueling outages. Closure of these valves during operation would cause the safety valve to lift, with the possibility of valve chatter. Valve chatter would damage this relief valve. Testing of these valves at power would cause equipment damage. Therefore, these valves will be tested during scheduled refueling outages. As above, additional Containment penetrations and Containment isolation valves introduce additional unnecessary potential pathways for radioactive release following a postulated accident. Thus, the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22 are met.

9. Feedwater split flow bypass valves (close) (Unit 2 only)

Feedwater split flow bypass valves are routinely tested during refueling outages. Closure of these valves during operation would divert all feedwater flow to the preheater region of the steam generator which may cause flow induced tube failures in the preheater region of the steam generator, and may induce excessive thermal transients in the nozzle and the connecting piping when flow is transferred to the auxiliary feedwater nozzle from the main feedwater line during unloading. As above, closure of these valves may damage other equipment. Thus, the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22 are met.

10. Feedwater isolation bypass valves (close)

These valves are routinely tested during refueling outages. Slave relay tests are accomplished as described in Section 7.3.2.2.5. To test closure on a Feedwater isolation signal at power would require that the valves be manually isolated and that the interlocks with the associated Unit 2 FWIV be defeated on all four Unit 2 FIBVs at the same time. Therefore, the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22 are met.

11. Feedwater preheater bypass valves (close) (Unit 2 only)

These valves are routinely tested during refueling outages. Slave relay tests are accomplished as described in Section 7.3.2.2.5. To test closure on a Feedwater isolation signal at power would require that the valves be manually isolated and that the interlocks with the associated FWIV be defeated on all four FPBVs at the same time. Therefore, the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22 are met. Control circuits allow the valves to be stroked individually using the associated hand switch; however, stroking the valves in this manner requires that they first be manually isolated.

12. Feedwater control bypass valves (close)

These valves are routinely tested during refueling outages. To stroke them at power would adversely affect normal operation of the plant. These valves are required to be open during startup and low loads operation prior to opening the feedwater control valves. Therefore the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22 are met.

13. Closing chilled water supply and return header to chilled water recirculation pump isolation valves.

These valves are routinely tested during refueling outages. To close them at power would adversely affect the operability of neutron detector well cooling units. Therefore the guidelines of Regulatory Position D.4 of regulatory guide 1.22 are met.

14. Closing instrument air to containment isolation valve.

This valve is routinely tested during refueling outages. To close it at power would adversely affect the operability of pneumatic equipment inside the containment. Therefore the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22 are met.

15. Closing ventilation chiller CCW supply and discharge control valves.

These valves are routinely tested during refueling outages. To close them at power would adversely affect the operability of the ventilation chiller and letdown chiller. Therefore the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22 are met.

16. Intentionally blank.

17. Generator trip on turbine trip

Generator trip cannot be tested at power because to test it, turbine trip has to be initiated. This circuit is routinely tested during refueling outages.

18. RHR containment sump suction isolation valves

Valves 1-8811A and 1-8811B, RHR containment recirculation sump isolation valves, cannot be safely exercised with the plant at power. The stroke test of these valves requires isolating the RHR pumps from the RWST to prevent gravity draining the RWST to the containment sump.

The absence of a check valve in the RHR suction line potentially could push water into the containment sump which would then require removal. The RHR pump suction header would then have to be partially drained to prevent water back flow to the sump rendering the pumps inoperable. An additional concern involves the ability to adequately vent and fill the system after testing. The additional risks encountered and the amount of time to perform testing do not justify the additional assurance gained by quarterly testing. These valves are routinely tested during refueling outages.

19. Normal charging isolation valves

Valves 1-8105 and 1-8106, normal charging isolation valve, cannot be exercised during power operation since this would interrupt normal charging flow which could result in loss of pressurizer level control. This valve will be full-stroke exercised during cold shutdown.

20. Normal letdown isolation valves

Valves 1-8152 and 1-8160, CVCS letdown containment isolation valves, cannot be exercised during power operation since this would result in a loss of normal letdown flow, which would stop the preheating of the charging water going through the regenerative heat exchanger. This lack of preheating would cause an unnecessary thermal shock to the charging line penetration. These valves will be exercised during refueling outages.

21. RWST charging pump suction isolation valves

Valves 1-LCV-112D and E, charging pump suction from RWST isolation valves, cannot be exercised during power operation since this would result in defeating the chemical balance attained by normal use of the CVCS. The subsequent reactivity transient could result in an uncontrolled plant shutdown. These valves will be exercised during refueling outages.

22. VCT outlet isolation valve

Valves 1-LCV-112B and C, volume control tank outlet isolation valves, cannot be exercised during plant operation since this would cause a loss of pressurizer level control, RCP seal injection, and letdown regenerative heat exchanger cooling. These valves will be exercised during refueling outages in accordance with the IST Plan.

23. High head safety injection isolation valves

Valves 1-8801A and B, high head safety injection isolation valves, cannot be opened during plant operation because opening the valves results in unnecessary thermal transients on the reactor coolant system cold legs and an uncontrolled level increase in the pressurizer. In addition, the unit shutdown is required to leak check the reactor coolant system pressure isolation check valves located downstream of the valves. These valves will be exercised during refueling outages in accordance with the IST Plan.

24. Selected valves from Inservice Testing Plan

FSAR Section 3.9B.6.2 states that the inservice testing of valves shall be in accordance with the Inservice Testing Plan. Inservice Testing Plan identifies which valves cannot be

tested at full power so as not to damage equipment or upset plant operation (as allowed by the ASME Code). These valves are identified by a footnote and a justification as to why the valve cannot be tested at full power. The guidelines of Regulatory Position D.4 of Regulatory Guide 1.22 are met.

7.1.2.6 Conformance to Regulatory Guide 1.47

The Bypassed and Inoperable Status Indication System (called Safety System Inoperable Indication (SSII) on CPNPP) conforms to the requirements of Regulatory Guide 1.47. The system is designed as follows:

1. The SSII is located in the Control Room and consists of one control board display for each safety train. Within each display are bypass lights for each of the systems listed in item 6.

   The system for each train consists of a lamp box, a horn and an electronics logic chassis. The lamp box is mounted on the front of the control board. The electronics logic chassis and the horn are mounted inside the control board.

   Each lamp box consists of twenty backlighted pushbuttons and “acknowledge,” “reset” and two “test” pushbuttons. Each backlighted pushbutton is capable of red and amber displays and there are separate test pushbuttons for the red and amber lamps.

   The inputs to each backlighted pushbutton are divided into two categories, primary inputs which give a red display and secondary inputs which give an amber display. The primary inputs are those inputs to a given system, from components within the given system itself, that will cause the given system to be bypassed or inoperative. The secondary inputs are those inputs from other (supporting) systems or other primary displays to the given system that will cause the given system to be bypassed or inoperative.

   The system functions like an annuniciator system in that activation of a field contact, or momentary actuation of a backlighted pushbutton causes the light in that pushbutton to flash and the horn to come on. Pressing the acknowledge button, silences the horn and the light becomes steady. Upon return to normal, the light stays on until “reset” button is pressed.

   For electrical schematic drawings, see drawings 2323-E1-0071, sheets 46 through 65, 67 and 68.

2. The SSII does not perform functions essential to mitigate the consequences of an accident, nor do administrative procedures require operator manual actions based solely on SSII displays. SSII is implemented as a non-safety grade system consistent with R.G. 1.47.

3. Electrical separation is based on analysis provided in Section 8.3. The interface with safety systems and components is such that no degradation of safety systems will occur because of an SSII failure.

4. The SSII display is automatically initiated for those inoperable conditions reasonable expected to occur more frequently than once per year when the affected system is normally required to be operable.

5. A means for manually initiating the SSII light exists for those maintenance or bypass activities not automatically initiated. The manual initiation consists of pressing the backlighted pushbutton used for display. This can only be cleared by again actuating the pushbutton.

6. An audible alarm is sounded when any bypass is automatically initiated.

   The list of systems included on each SSII display, along with a reference to the description of the system is as follows:

   a. Residual Heat Removal, (Section 5.4.7)

   b. Safety Injection, (Section 6.3)

   c. Containment Spray, (Section 6.5.2)

   d. Onsite power, diesel (Section 8.3)

   e. Preferred offsite power, (Section 8.3)

   f. Alternate offsite power, (Section 8.3)

   g. 480 VAC, (Section 8.3)

   h. Station Service Water, (Section 9.2.1)

   i. Auxiliary Feedwater, (Section 10.4.9)

   j. Component Cooling Water, (Section 9.2.2)

   k. Control Room HVAC, (Section 9.4.1)

   l. 125 VDC, (Section 8.3.2)

   m. 118 VAC, (Section 8.3.1)

   n. Safety Chilled Water System, (Section 9.4F)

   o. Primary Plant ESF ventilation exhaust system, (Section 9.4)

   A logic diagram showing typical implementation of this system is shown on Figure 7.1-4 for the Containment Spray System.

The design was verified as part of the Preoperational Test Program.

7.1.2.7 Conformance to Regulatory Guide 1.53 and IEEE Standard 379-1972

1. NSSS Systems:

The principles described in IEEE Standard 379-1972 were used in the design of the Westinghouse Protection System. The system complies with the intent of this standard and the additional guidance of Regulatory Guide 1.53 although the formal analyses gone beyond the required analyses and has performed a fault tree analysis, Reference [1]. The referenced topical report provides details of the analyses of the protection systems previously made to show conformance with the single failure criterion set forth in Section 4.2 of IEEE Standard 279-1971. The interpretation of single failure criterion provided by IEEE Standard 379-1972 does not indicate substantial differences with the Westinghouse interpretation of the criterion except in the methods used to confirm design reliability. Established design criteria in conjunction with sound engineering practices form the bases for the Westinghouse protection systems. The RTS and ESFAS are each redundant safety systems. The required periodic testing of these systems will disclose any failures or loss of redundancy which could have occurred in the interval between tests, thus ensuring the availability of these systems.

2. BOP Systems:

Listed below are the BOP portions of the plant safety system, and the auxiliary systems required for supprt of the safety systems:

System		Described in Section
ESF System:		
a.	Containment Spray	6.2.2, 6.5.2
b.	Containment Isolation	6.2.4, 10.3 and 10.4.7
c.	Control Room Air Conditioning	6.4.2.2 and 9.4
d.	Auxiliary Feedwater	10.4.9
e.	ESF Filters	6.5
ESF Support System:		
a.	Component Cooling Water	9.2.10
b.	Station Service Water	9.2.1
c.	Onsite Power Supply	8.3, 9.5 and 9.4C
d.	ESF Ventilation	9.4.5
e.	Safety Chilled Water	9.4F
f.	Service Water Intake Structure Ventilation	9.4B
g.	UPS Ventilation System	9.4C.8

The instrumentation and controls, and associated power supplies, for the listed systems are designed to meet the principle of redundancy and the requirements for electrical independence and physical separation of redundant trains. The redundant components, their locations, and arrangements are protected from common mode failures resulting from missiles, pipe whip, fire, harsh environment etc. For each of the listed systems, a failure mode and effects analysis has been determined to ensure compliance with the single failure criterion. Required periodic testing, as described in Section 7.1.2.5, will detect potential failures or loss of redundance which may have occurred between test intervals. Also, anomalous indication and alarms during normal plant operation provide additional means for detection of failures.

Thus the BOP safety systems and auxiliary systems required for support of safety systems meet the requirements of Regulatory Guide 1.53 and IEEE STD 379-1972.

7.1.2.8 Conformance to Regulatory Guide 1.63

Refer to Section 8.3.1.2.

7.1.2.9 Conformance to IEEE Standard 317-1972

Refer to Section 8.3.1.2.

7.1.2.10 Conformance to IEEE Standard 336-1971

Refer to Section 8.3.1.2.

7.1.2.11 Conformance to IEEE Standard 338-1971

The periodic testing of the RTS and ESFAS conforms to the requirements of IEEE Standard 338-1971 with the following comments:

1. The surveillance requirements of the Technical Specifications for Protection System ensure that the system functional operability is maintained comparable to the original design standards. Periodic tests at frequent intervals verify this capability for the system, excluding sensors.

   Overall protection systems response times are verified by test procedures detailed by Luminant Power. Sensors are adequately demonstrated for the design by vendor testing, insitu tests in operating plants with appropriately similar design, or by suitable type testing. The Nuclear Instrumentation System detectors are excluded since they exhibit response time characteristics such that delays attributable to them are negligible in the overall channel response time required for safety.

   Sensors will be periodically tested to ensure their response times are within the minimum performance requirements of the design basis. This may be done by either (1) in place on site or off site test measurements or (2) utilizing the replacement sensors with certified response times.

   For pressure and differential pressure transmitters, in place on site response time measurements will involve application of step inputs about each setpoint for which

response time determination is required. This is consistent with original Westinghouse specifications as well as with qualification testing.

The steps' initial value will be 5% of span, in the reset direction from the setpoint of interest. The steps' final value will be 5% of span, in the tripped direction, from the setpoint of interest. The response time will be that time required for the transmitter's output to transition from its initial value at the time of initiation of the step input to the value corresponding to the setpoint of interest. For each transmitter, these steps are applied about all associated setpoints for which a response time determination is required.

For those transmitters only requiring response time determination about a single setpoint, an additional step is applied as a linearity check. This additional step will utilize the same ±5% of span for initial and final values as described above. However, these values will be applied about 50% of span versus an actual setpoint.

An alternative to the step-input Sensor Response Time Testing (SRTT) determination method for pressure and differential pressure devices is the White Noise Analysis technique. This involves measuring the natural fluctuations existing at the transmitters' output during normal operation. The signal is then mathematically analyzed and a response time is extracted. The resultant White Noise response time is then correlated to the step-input response time. Subsequent White Noise tests are compared to the initial White Noise response to determine if degradation of time response has occurred.

For resistance temperature detectors (RTDs), in place/on site response time testing will be conducted using the Loop Current Step Response (LCSR) method described in EPRI report NP-834. Westinghouse design specifications placed on their RTD suppliers reference a plunge type test for determination of RTD response time. However, a study conducted by Analysis and Measurement Services (AMS) for CPNPP (Report AMS-TU8402RO), compared plunge testing with LCSR testing for the type RTDs and thermal wells used at CPNPP. The report concludes that the agreement between the two test methods demonstrates the LCSR testability of the CPNPP RTDs.

Technical Specifications require response time verification on at least 18 month intervals. Each verification shall include at least one logic train such that both logic trains are verified at least once per 36 months and one channel per function such that all channels are verified at least once every N times 18 months, where N is the total number of redundant channels in a specific protective function.

Verification of the overall response time at the specified time intervals provides assurance that the protective and engineered safety features action function associated with each channel is completed within the time limit assumed in the accident analyses.

2. The reliability goals specified in Section 4.2 of IEEE Standard 338-1971 and adequacy of time intervals are described in Reference 1.

3. The periodic time interval discussed in Section 4.3 of IEEE Standard 338-1971, and specified in the Technical Specifications, is conservatively selected to assure that equipment associated with protection functions has not drifted beyond its minimum performance requirements. If any protection channel appears to be marginal or requires

more frequent adjustments due to plant condition changes, the time interval will be decreased to accommodate the situation until the marginal performance is resolved.

4. The test interval discussed in Section 5.2 of IEEE Standard 338-1971 is developed primarily on past operating experience and modified if necessary to assure that system and subsystem protection is reliably provided. Analytic methods for determining reliability are not used to determine test interval.

5. Testing of the underfrequency relay for Reactor Coolant Pumps, described in Section 7.2.2.2.3.10, conforms to the requirements of IEEE Standards 279-1971 and 338-1971 with the following comment.

   Testing is accomplished by introducing and varying a substitute input to the sensor of the same nature as the introduced variable. The inoperable condition is administratively controlled and is also indicated as soon as the relay setpoint is verified.

Based on the scope definition given in IEEE Standard 338-1971, no other instrumentation described in Chapter 7 is required to comply with this standard.

REFERENCES

1. Gangloff, W. C. and Loftus, W. D., “An Evaluation of Solid State Logic Reactor Protection in Anticipated Transients,” WCAP-7706-L (Proprietary) and WCAP-7706 (Non-Proprietary), February 1973.

2. Siroky, R. M. and Marasco, F. W., “7300 Series Process Control System Noise Tests,” WCAP-8892-A, April 1977.

3. Morgan, C. E., “Elimination of Periodic Protection Channel Response Time Tests,” WCAP-14036-P-A, Revision 1, October 6, 1998.

4. Letter NS-CE-604, dated March 31, 1975, C. Eicheldinger (Westinghouse) to the Secretary of the Nuclear Regulatory Commission.

5. NRC Regulatory Guide 1.75, Physical Independence of Electric Systems, Revision 1, January 1975, U.S. Nuclear Regulatory Commission.

6. IEEE 384-1974, Trial-Use Standard Criteria for Separation of Class 1E Equipment and Circuits.

TABLE 7.1-1
LISTING OF APPLICABLE CRITERIA

(Sheet 1 of 8)

	Criteria	Title	Conformance Discussed In:
1.	General Design Criteria (GDC), Appendix A to 10CFR50		
	GDC 1	Quality Standards and Records	3.1, 7.2.2.2
	GDC 2	Design Bases for Protection Against Natural Phenomena	3.1, 7.2.1.1.11
	GDC 3	Fire Protection	3.1, 9.5
	GDC 4	Environmental and Missile Design Bases	3.1, 7.2.2.2
	GDC 5	Sharing of Structures, Systems, and Components	3.1
	GDC 10	Reactor Design	3.1, 7.2.2.2
	GDC 12	Suppression of Reactor Power Oscillations	3.1
	GDC 13	Instrumentation and Control	3.1, 7.3.1, 7.3.2
	GDC 15	Reactor Coolant System Design	3.1, 7.2.2.2
	GDC 19	Control Room	3.1, 6.4, 9.4
	GDC 20	Protection System Functions	3.1, 7.1.2.1.5, 7.2.2.2, 7.3.1, 7.3.2

TABLE 7.1-1
LISTING OF APPLICABLE CRITERIA

(Sheet 2 of 8)

Criteria	Title	Conformance Discussed In:
GDC 21	Protection System Reliability and Testability	3.1, 7.1.2.1.5, 7.2.2.2, 7.3.2
GDC 22	Protection System Independence	3.1, 7.1.2.1.5, 7.1.2.2, 7.2.2.2, 7.3.1, 7.3.2
GDC 23	Protection System Failure Modes	3.1, 7.2.2.2, 7.3.1, 7.3.2
GDC 24	Separation of Protection and Control Systems	3.1, 7.2.2.2, 7.3.1, 7.3.2
GDC 25	Protection System Requirements for Reactivity Control Malfunctions	3.1, 7.3.2
GDC 26	Reactivity Control System Redundancy and Capability	3.1, 7.7
GDC 27	Combined Reactivity Control Systems Capability	3.1, 7.3.1, 7.3.2
GDC 28	Reactivity Limits	3.1, 7.3.1, 7.3.2
GDC 29	Protection Against Anticipated Operational Occurrences	3.1, 7.2.2.2
GDC 30	Quality of Reactor Coolant Pressure Boundary	3.1, 5.2.5, 7.6.2
GDC 33	Reactor Coolant Makeup	3.1, 6.3, 9.3
GDC 34	Residual Heat Removal	3.1, 5.4.7

TABLE 7.1-1
LISTING OF APPLICABLE CRITERIA

(Sheet 3 of 8)

Criteria	Title	Conformance Discussed In:
GDC 35	Emergency Core Cooling	3.1, 7.3.1, 7.3.2
GDC 37	Testing of Emergency Core Cooling System	3.1, 7.3.1, 7.3.2
GDC 38	Containment Heat Removal	3.1, 6.2.2
GDC 40	Testing of Containment Heat Removal System	3.1, 6.2.2
GDC 41	Containment Atmosphere Cleanup	3.1, 6.2.2, 6.5.2
GDC 43	Testing of Containment Atmosphere Cleanup System	3.1, 6.5.2
GDC 44	Cooling Water	3.1, 9.2.2
GDC 46	Testing of Cooling Water System	3.1, 9.2.2
GDC 50	Containment Design Basis	3.1
GDC 54	Piping Systems Penetrating Containment	3.1, 6.2.4
GDC 55	Reactor Coolant Pressure Boundary Penetrating Containment	3.1, 6.2.4
GDC 56	Primary Containment Isolation	3.1, 7.3.1, 6.2.4
GDC 57	Closed Systems Isolation Valves	3.1, 6.2.4

TABLE 7.1-1
LISTING OF APPLICABLE CRITERIA

(Sheet 4 of 8)

Criteria		Title	Conformance Discussed In:
	GDC 63	Monitoring Fuel & Waste Storage	3.1, 11.5, 12.3.4
	GDC 64	Monitoring Radioactivity Releases	3.1, 11.5, 12.3.4 12.3.5
2.	Institute of Electrical and Electronics Engineers (IEEE) Standards:		
	IEEE Std 279-1971 (ANSI N42.7-1972)	Criteria for Protection Systems for Nuclear Power Generating Stations	7.1, 7.2, 7.3, 7.4 7.5, 7.6, 7.7
	IEEE Std 308-1974	Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations	7.6.1, 7.1.1.1.3, 8.3.1
	IEEE Std 317-1976 (ANSI N45.3-1973)	Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations	8.3.1.2
	IEEE Std 323-1974	Qualifying Class 1E Equipment for Nuclear Power Generating Stations	3.11B, 3.11N
	IEEE Std 336-1971 (ANSI N45.2.4-1972)	Installation, Inspection and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations	8.3.1.2

TABLE 7.1-1
LISTING OF APPLICABLE CRITERIA

(Sheet 5 of 8)

Criteria		Title	Conformance Discussed In:
	IEEE Std 338-1971 (ANSI N41.3)	Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems	7.1.2.11
	IEEE Std 344-1971 (ANSI N41.7)	Trial-Use Guide for Seismic Qualification of Class I Electric Equipment for Nuclear Power Generating Stations	3.10B, 3.10N
	IEEE Std 379-1972 (ANSI N41.2)	Trial-Use Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems	7.1.2.7
	IEEE Std 384-1974 (ANSI N41.14)	Trial-Use Standard Criteria for Separation of Class 1E Equipment and Circuits	7.1.2.2.1
3.	Regulatory Guides (RG)		
	RG 1.6	Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems	1A(B), 8.3
	RG 1.7	Control of Combustible Gas Concentrations in Containment Following a Loss of Coolant Accident	1A(B), 6.2.5
	RG 1.11	Instrument Lines Penetrating Primary Reactor Containment	1A(B), 1A(N), 7.3.1.1.2

TABLE 7.1-1
LISTING OF APPLICABLE CRITERIA

(Sheet 6 of 8)

Criteria	Title	Conformance Discussed In:
RG 1.12	Instrumentation for Earthquakes	1A(B)
RG 1.22	Periodic Testing of Protection System Actuation Functions	1A(N), 1A(B), 7.1.2.5, 7.3.2.2.5
RG 1.29	Seismic Design Classification	1A(B), 1A(N)
RG 1.30	Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment	1A(B), 1A(N), Chapter 17
RG 1.32	Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants	1A(B), 8.3
RG 1.40	Qualifications Tests of Continuous- Duty Motors Installed Inside the Containment of Water-Cooled Nuclear Power Plants	1A(B), 1A(N)
RG 1.45	Reactor Coolant Pressure Boundary Leakage Detection Systems	1A(B), 5.2.5
RG 1.47	Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems	1A(B), 7.1.2.6
RG 1.53	Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems	1A(N), 7.1.2.7, 1A(B)

TABLE 7.1-1
LISTING OF APPLICABLE CRITERIA

(Sheet 7 of 8)

Criteria	Title	Conformance Discussed In:
RG 1.62	Manual Initiation of Protection Actions	1A(N), 7.3.2.2.7
RG 1.63	Electric Penetration Assemblies in Containment Structures for Light Water-Cooled Nuclear Power Plants	1A(B), 8.3.1.2
RG 1.67	Installation of Overpressure Protection Devices	1A(B), 3.9N.3.3, 3.9B.3.3
RG 1.68	Initial Test Programs for Water-Cooled Reactor Power Plants	1A(B), Chapter 14
RG 1.70	Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants	1A(B), Chapter 7
RG 1.73	Qualification Test of Electric Operators Installed Inside the Containment of Nuclear Power Plants	1A(B), 1A(N), 3.10B, 3.10N, 3.11B, 3.11N
RG 1.75	Physical Independence of Electric Systems	1A(B), 1A(N), 7.1.2.2.1, 8.3
RG 1.78	Assumptions for Evaluating the Habitability of a Nuclear Power Power Plant Control Room During a Postulated Hazardous Chemical Release	1A(B), 2.2, 6.4
RG 1.80	Preoperational Testing of Instrument Air Systems	1A(B), Chapter 14

TABLE 7.1-1
LISTING OF APPLICABLE CRITERIA

(Sheet 8 of 8)

Criteria	Title	Conformance Discussed In:
RG 1.89	Qualification of Class 1E Equipment for Nuclear Power Plants	1A(B), 1A(N), 3.11B, 3.11N
RG 1.95	Protection of Nuclear Power Plant Control Room Operators against an Accidental Chlorine Release	1A(B)
RG 1.97	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During & Following an Accident	1A(N), 1A(B), 7.5
RG 1.100	Seismic Qualification of Electric Equipment for Nuclear Power Plants	1A(N), 1A(B), 3.10B, 3.10N
RG 1.105	Instrument Spans and Setpoints	1A(N), 1A(B)
RG 1.106	Thermal Overload Protection for Electric Motors on Motor-Operated Valves	1A(B), 8.3
RG 1.118	Periodic Testing of Electric Power & Protection Systems	1A(N), 1A(B), 7.1.2.11
RG 1.120	Fire Protection Guidelines for Power Plants	1A(N), 1A(B), 9.5

TABLE 7.1-2.2
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR REACTOR TRIP SYSTEM (1,7)

(Sheet 1 of 4)

	RTS & NSSS Inputs	Turbine Trip-Reactor Trip	RC Pump Under Voltage-Under Frequency Trips
GDC 1	X	X	X
GDC 2	X	X	X
GDC 3	X	X	X
GDC 4	X	X	X
GDC 5	X	X	X
GDC 10	X	X	X
GDC 12	X	-	-
GDC 13	X	X	X
GDC 15	X	X	X
GDC 19	X	X	X
GDC 20	X	X	X
GDC 21	X	X	X
GDC 22	X	X	X
GDC 23	X	X	X
GDC 24	X	X	X
GDC 25	X	-	-
GDC 26	X	-	-
GDC 27	X	-	-
GDC 28	X	-	-
GDC 29	X	X	X
GDC 30	-	-	-
GDC 33	-	-	-

TABLE 7.1-2.2
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR REACTOR TRIP SYSTEM (1,7)

(Sheet 2 of 4)

	RTS & NSSS Inputs	Turbine Trip-Reactor Trip	RC Pump Under Voltage-Under Frequency Trips
GDC 34	-	-	-
GDC 35	-	-	-
GDC 37	-	-	-
GDC 38	-	-	-
GDC 40	-	-	-
GDC 41	-	-	-
GDC 43	-	-	-
GDC 44	-	-	-
GDC 46	-	-	-
GDC 50	-	-	-
GDC 54	-	-	-
GDC 55	-	-	-
GDC 56	-	-	-
GDC 57	-	-	-
GDC 63	-	-	-
GDC 64	-	-	-
RG 1.6	-	-	-
RG 1.7	-	-	-
RG 1.11	-	-	-
RG 1.12(2)			
RG 1.22	X	X	X
RG 1.29	X	X	X

TABLE 7.1-2.2
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR REACTOR TRIP SYSTEM (1,7)

(Sheet 3 of 4)

	RTS & NSSS Inputs	Turbine Trip-Reactor Trip	RC Pump Under Voltage-Under Frequency Trips
RG 1.30	X	X	X
RG 1.32	-	-	-
RG 1.45	-	-	-
RG 1.47	X	X	X
RG 1.53	X	X	X
RG 1.62	X	-	-
RG 1.63(3)			
RG 1.67(4)			
RG 1.68(5)			
RG 1.70	X	X	X
RG 1.75	X	X	X
RG 1.78	-	-	-
RG 1.80(5)			
RG 1.89	X	X	X
RG 1.95	-	-	-
RG 1.97	-	-	-
RG 1.100	X	X	X
RG 1.105	X	X	X
RG 1.118	X	X	X
RG 1.120(6)			
IEEE STD 279	X	X	X

TABLE 7.1-2.2
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR REACTOR TRIP SYSTEM (1,7)

(Sheet 4 of 4)

	RTS & NSSS Inputs	Turbine Trip-Reactor Trip	RC Pump Under Voltage-Under Frequency Trips
IEEE STD 308	X	-	-
IEEE STD 317(3)			
IEEE STD 323	X	X	X
IEEE STD 336	X	X	X
IEEE STD 338	X	X	X
IEEE STD 344	X	X	X
IEEE STD 379	X	X	X
IEEE STD 384	X	X	X

Notes:

1. The scope of applicability is instrumentation and control and NSSS electrical power supply only.
2. Refer to FSAR Section 3.7B.4 and Appendix 1A(B).
3. Refer to FSAR Section 8.3.1.2.1 and Appendix 1A(B).
4. Refer to FSAR Section 3.9B.3.3 and Appendix 1A(B).
5. Refer to FSAR Section 14.2 and Appendix 1A(B).
6. Refer to FSAR Section 9.5.1 and Appendix 1A(B).
7. X Signifies compliance as discussed or qualified in the FSAR sections referenced in Table 7.1-1.

   - Not applicable.

TABLE 7.1-2.3
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR ENGINEERED SAFETY FEATURES SYSTEM (1,7)

(Sheet 1 of 5)

	ESF								ESF SUPPORT						
	EMERGENCY				CONTROL ROOM				COMP. STATION			SAFETY	SERVICE WATER	ONSITE	
	ESFAS	CORE COOLING	CONT. SPRAY	CONT. ISOLATION	AUXILIARY FEEDWATER	AIR CONDITIONING	COMBUSTIBLE GAS CONTROL	ESF FILTER	COOLING WATER	SERVICE WATER	ESF VENT.	CHILLED WATER	INTAKE STRUC. HVAC	POWER SUPPLY	UPS VENT.
GDC 1	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 2	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 3	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 4	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 5	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 10	X	X	-	-	X	-	-	-	-	-	-	-	-	-	-
GDC 12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 13	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 15	X	X	-	-	X	-	-	-	-	-	-	-	-		-
GDC 19	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 20	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 21	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 22	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 23	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 24	X	X	X	X	X	X	X	X	X	X	X	X	X	X	-
GDC 25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

TABLE 7.1-2.3
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR ENGINEERED SAFETY FEATURES SYSTEM (1,7)

(Sheet 2 of 5)

	ESF								ESF SUPPORT						
	EMERGENCY			CONTROL ROOM					COMP. STATION			SAFETY	SERVICE WATER	ONSITE	
	ESFAS	CORE COOLING	CONT. SPRAY	CONT. ISOLATION	AUXILIARY FEEDWATER	AIR CONDITIONING	COMBUSTIBLE GAS CONTROL	ESF FILTER	COOLING WATER	SERVICE WATER	ESF VENT.	CHILLED WATER	INTAKE STRUC. HVAC	POWER SUPPLY	UPS VENT.
GDC 27	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 29	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 35	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 37	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 38	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-
GDC 40	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-
GDC 41	-	-	X	-	-	-	X	-	-	-	-	-	-	-	-
GDC 43	-	-	X	-	-	-	X	-	-	-	-	-	-	-	-
GDC 44	-	-	-	-	-	X	-	-	X	X	-	X	-	-	-
GDC 46	-	-	-	-	-	X	-	-	X	X	-	X	-	-	-
GDC 50	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-
GDC 54	-	X	X	X	X	-	X	-	X	-	-	-	-	-	-
GDC 55	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-

TABLE 7.1-2.3
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR ENGINEERED SAFETY FEATURES SYSTEM (1,7)

(Sheet 3 of 5)

	ESF								ESF SUPPORT						
	EMERGENCY			CONTROL ROOM					COMP. STATION			SAFETY	SERVICE WATER	ONSITE	
	ESFAS	CORE COOLING	CONT. SPRAY	CONT. ISOLATION	AUXILIARY FEEDWATER	AIR CONDITIONING	COMBUSTIBLE GAS CONTROL	ESF FILTER	COOLING WATER	SERVICE WATER	ESF VENT.	CHILLED WATER	INTAKE STRUC. HVAC	POWER SUPPLY	UPS VENT.
GDC 56	-	-	X	X	-	-	X	-	X	-	-	-	-	-	-
GDC 57	-	-	-	X	X	-	-	-	X	-	-	-	-	-	-
GDC 63	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GDC 64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RG 1.6	-	-	-	-	-	-	-	-	-	-	-	-	-	X	-
RG 1.7	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-
RG 1.11	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RG 1.12[(2)]															
RG 1.22	X	X	X	X	X	X	-	X	X	X	X	X	-	X	X
RG 1.29	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
RG 1.30	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
RG 1.32	-	-	-	-	-	-	-	-	-	-	-	-	-	X	-
RG 1.45	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RG 1.47	X	X	X	X	X	X	-	X	X	X	-	X	-	X	X
RG 1.53	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
RG 1.62	X	-	-	-	-	-	-	-	-	-	-	-	-	X	-

TABLE 7.1-2.3
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR ENGINEERED SAFETY FEATURES SYSTEM (1,7)

(Sheet 4 of 5)

	ESF								ESF SUPPORT						
	EMERGENCY			CONTROL ROOM					COMP. STATION			SAFETY	SERVICE WATER	ONSITE	
	ESFAS	CORE COOLING	CONT. SPRAY	CONT. ISOLATION	AUXILIARY FEEDWATER	AIR CONDITIONING	COMBUSTIBLE GAS CONTROL	ESF FILTER	COOLING WATER	SERVICE WATER	ESF VENT.	CHILLED WATER	INTAKE STRUC. HVAC	POWER SUPPLY	UPS VENT.
RG 1.63[3]															
RG 1.67[4]															
RG 1.68[5]															
RG 1.70	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
RG 1.73	-	X	-	X	-	-	X	-	X	-	-	-	-	-	-
RG 1.75	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
RG 1.78	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-
RG 1.80[5]															
RG 1.89	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
RG 1.95	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RG 1.97	-	X	X	X	X	X	X	X	X	X	X	X	X	X	X
RG 1.100	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
RG 1.105	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
RG 1.118	X	-	-	-	-	-	-	-	-	-	-	X	-	X	-
RG 1.120[6]															
IEEE - 279	X	-	-	-	-	-	-	-	-	-	-	-	-	X	-
IEEE - 308	X	-	-	-	-	-	-	-	-	-	-	-	-	X	-

TABLE 7.1-2.3
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR ENGINEERED SAFETY FEATURES SYSTEM (1,7)

(Sheet 5 of 5)

	ESF								ESF SUPPORT						
	EMERGENCY			CONTROL ROOM					COMP. STATION			SAFETY	SERVICE WATER	ONSITE	
	ESFAS	CORE COOLING	CONT. SPRAY	CONT. ISOLATION	AUXILIARY FEEDWATER	AIR CONDITIONING	COMBUSTIBLE GAS CONTROL	ESF FILTER	COOLING WATER	SERVICE WATER	ESF VENT.	CHILLED WATER	INTAKE STRUC. HVAC	POWER SUPPLY	UPS VENT.
IEEE - 317[3]															
IEEE - 323	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE - 336	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE - 338	X	X	X	X	X	X	-	X	X	X	X	X	-	X	X
IEEE - 344	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE - 379	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE - 384	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

Notes:

1. The scope of applicability is instrumentation and control and NSSS electrical power supply only.
2. Refer to FSAR Section 3.7B.4 and Appendix 1A(B).
3. Refer to FSAR Section 8.3.1.2.1 and Appendix 1A(B).
4. Refer to FSAR Section 3.9B.3.3. and Appendix 1A(B).
5. Refer to FSAR Section 14.2 and Appendix 1A(B).
6. Refer to FSAR Section 9.5.1 and Appendix 1A(B).
7. X Signifies compliance as discussed or qualified in the FSAR sections referenced in Table 7.1-1.

   - Not applicable.

TABLE 7.1-2.4
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR SYSTEMS REQUIRED FOR SAFE SHUTDOWN (1,8)

(Sheet 1 of 5)

	HOT STANDBY											
	REQUIRED			SUPPORT								
	AUXILIARY FEEDWATER	CVCS BORON ADDITION	ATMOS. STEAM RELIEF (7)	COMP. COOLING WATER	STATION SERVICE WATER	CONTROL ROOM AIR COND.	ON SITE POWER SUPPLY	SAFETY CHILLED WATER	UPS VENT	ESF VENT	REMOTE SHUTDOWN	COLD SHUTDOWN
GDC 1	X	X	X	X	X	X	X	X	X	X	X	-
GDC 2	X	X	X	X	X	X	X	X	X	X	X	-
GDC 3	X	X	X	X	X	X	X	X	X	X	X	-
GDC 4	X	X	X	X	X	X	X	X	X	X	X	-
GDC 5	X	X	X	X	X	X	X	X	X	X	X	-
GDC 10	X	X	X	-	-	-	-	-	-	-	-	-
GDC 12	-	-	-	-	-	-	-	-	-	-	-	-
GDC 13	X	X	X	X	X	X	X	X	X	X	X	X
GDC 15	X	-	X	-	-	-	-	-	-	-	-	-
GDC 19	X	X	X	X	X	X	X	X	X	X	X	X
GDC 20	-	-	-	-	-	-	-	-	-	-	-	-
GDC 21	-	-	-	-	-	-	-	-	-	-	-	-
GDC 22	-	-	-	-	-	-	-	-	-	-	-	-
GDC 23	-	-	-	-	-	-	-	-	-	-	-	-
GDC 24	X	X	-	X	X	X	X	X	-	-	X	X
GDC 25	-	-	-	-	-	-	-	-	-	-	-	-
GDC 26	-	X	-	-	-	-	-	-	-	-	-	-
GDC 27	-	X	-	-	-	-	-	-	-	-	-	-

TABLE 7.1-2.4
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR SYSTEMS REQUIRED FOR SAFE SHUTDOWN (1,8)

(Sheet 2 of 5)

	HOT STANDBY											
	REQUIRED			SUPPORT								
	AUXILIARY FEEDWATER	CVCS BORON ADDITION	ATMOS. STEAM RELIEF (7)	COMP. COOLING WATER	STATION SERVICE WATER	CONTROL ROOM AIR COND.	ON SITE POWER SUPPLY	SAFETY CHILLED WATER	UPS VENT	ESF VENT	REMOTE SHUTDOWN	COLD SHUTDOWN
GDC 28	-	X	-	-	-	-	-	-	-	-	-	-
GDC 29	-	X	-	-	-	-	-	-	-	-	X	X
GDC 30	-	-	-	-	-	-	-	-	-	-	-	-
GDC 33	-	X	-	-	-	-	-	-	-	-	-	-
GDC 34	-	-	-	-	-	-	-	-	-	-	X	X
GDC 35	-	-	-	-	-	-	-	-	-	-	-	-
GDC 37	-	-	-	-	-	-	-	-	-	-	-	-
GDC 38	-	-	-	-	-	-	-	-	-	-	-	-
GDC 40	-	-	-	-	-	-	-	-	-	-	-	-
GDC 41	-	-	-	-	-	-	-	-	-	-	-	-
GDC 43	-	-	-	-	-	-	-	-	-	-	-	-
GDC 44	-	-	-	X	X	X	-	X	-	-	-	-
GDC 46	-	-	-	X	X	X	-	X	-	-	-	-
GDC 50	-	-	-	-	-	-	-	-	-	-	-	-
GDC 54	X	X	-	X	-	-	-	-	-	-	-	-
GDC 55	-	X	-	-	-	-	-	-	-	-	-	-
GDC 56	-	-	-	X	-	-	-	-	-	-	-	-
GDC 57	-	-	-	X	-	-	-	-	-	-	-	-

TABLE 7.1-2.4
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR SYSTEMS REQUIRED FOR SAFE SHUTDOWN (1,8)

(Sheet 3 of 5)

	HOT STANDBY											
	REQUIRED			SUPPORT								
	AUXILIARY FEEDWATER	CVCS BORON ADDITION	ATMOS. STEAM RELIEF (7)	COMP. COOLING WATER	STATION SERVICE WATER	CONTROL ROOM AIR COND.	ON SITE POWER SUPPLY	SAFETY CHILLED WATER	UPS VENT	ESF VENT	REMOTE SHUTDOWN	COLD SHUTDOWN
GDC 63	-	-	-	-	-	-	-	-	-	-	-	-
GDC 64	-	-	-	-	-	-	-	-	-	-	-	-
RG 1.6	-	-	-	-	-	-	X	-	-	-	-	-
RG 1.7	-	-	-	-	-	-	-	-	-	-	-	-
RG 1.11	-	-	-	-	-	-	-	-	-	-	-	-
RG 1.12(2)												
RG 1.22	X	X	-	X	X	X	X	X	X	X	-	-
RG 1.29	X	X	-	X	X	X	X	X	X	X	X	-
RG 1.30	X	X	-	X	X	X	X	X	X	X	X	-
RG 1.32	-	-	-	-	-	-	X	-	-	-	-	-
RG 1.45	-	-	-	-	-	-	-	-	-	-	-	-
RG 1.47	X	X	-	X	X	X	X	X	X	X	X	X
RG 1.53	X	-	-	X	X	X	X	X	X	X	X	-
RG 1.62	-	-	-	-	-	-	-	-	-	-	-	-
RG 1.63(3)												
RG 1.67(4)												
RG 1.68(5)												
RG 1.70	X	X	-	X	X	X	X	X	X	X	X	X

TABLE 7.1-2.4
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR SYSTEMS REQUIRED FOR SAFE SHUTDOWN (1,8)

(Sheet 4 of 5)

	HOT STANDBY											
	REQUIRED			SUPPORT								
	AUXILIARY FEEDWATER	CVCS BORON ADDITION	ATMOS. STEAM RELIEF (7)	COMP. COOLING WATER	STATION SERVICE WATER	CONTROL ROOM AIR COND.	ON SITE POWER SUPPLY	SAFETY CHILLED WATER	UPS VENT	ESF VENT	REMOTE SHUTDOWN	COLD SHUTDOWN
RG 1.73	-	-	-	X	-	-	-	-	-	-	-	-
RG 1.75	X	X	-	X	X	X	X	X	X	X	X	-
RG 1.78	-	-	-	-	-	X	-	-	-	-	-	-
RG 1.80[5]												
RG 1.89	X	X	-	X	X	X	X	X	X	X	-	-
RG 1.95	-	-	-	-	-	X	-	-	-	-	-	-
RG 1.97[9]	-	-	-	-	-	-	-	-	-	-	-	-
RG 1.100	X	X	-	X	X	X	X	X	X	X	-	-
RG 1.105	X	X	-	X	X	X	X	X	X	X	-	-
RG 1.118	-	-	-	-	-	-	X	-	-	-	-	-
RG 1.120[6]												
IEEE STD 279	-	-	-	-	-	-	-	-	-	-	X	-
IEEE STD 308	-	-	-	-	-	-	X	-	-	-	-	-
IEEE STD 317[3]												
IEEE STD 323	X	X	-	X	X	X	X	X	X	X	-	-
IEEE STD 336	X	X	-	X	X	X	X	X	X	X	X	-
IEEE STD 338	X	-	-	X	X	X	X	X	X	X	-	-
IEEE STD 344	X	X	-	X	X	X	X	X	X	X	-	-

TABLE 7.1-2.4
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR SYSTEMS REQUIRED FOR SAFE SHUTDOWN (1,8)

(Sheet 5 of 5)

	HOT STANDBY											
	REQUIRED			SUPPORT								
	AUXILIARY FEEDWATER	CVCS BORON ADDITION	ATMOS. STEAM RELIEF (7)	COMP. COOLING WATER	STATION SERVICE WATER	CONTROL ROOM AIR COND.	ON SITE POWER SUPPLY	SAFETY CHILLED WATER	UPS VENT	ESF VENT	REMOTE SHUTDOWN	COLD SHUTDOWN
IEEE STD 379	X	-	-	X	X	X	X	X	X	X	X	-
IEEE STD 384	X	X	-	X	X	X	X	X	X	X	X	-

Notes:

1. The scope of applicability is instrumentation & control and electrical power supply only.
2. Refer to FSAR Section 3.7B.4 and Appendix 1A(B).
3. Refer to FSAR Section 8.3.1.2.1 and Appendix 1A(B).
4. Refer to FSAR Section 3.9B.3.3. and Appendix 1A(B).
5. Refer to FSAR Section 14.2 and Appendix 1A(B).
6. Refer to FSAR Section 9.5.1 and Appendix 1A(B).
7. Atmospheric steam relief is provided by self-actuated code safety valves, which have no associated 1 & C or electrical power supplies. GDC's indicated apply to these safety valves.
8. X Signifies compliance as discussed or qualified in the FSAR Sections referenced in Table 7.1-1.

   - Not applicable.
9. See Table 7.1-2.3.

TABLE 7.1-2.5
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR SAFETY RELATED DISPLAY INSTRUMENTS (1, 8)

(Sheet 1 of 4)

	ACCIDENT MONITORS
GDC 1	X
GDC 2	X
GDC 3	X
GDC 4	X
GDC 5	X
GDC 10	-
GDC 12	-
GDC 13	X
GDC 15	-
GDC 19	X
GDC 20	-
GDC 21	-
GDC 22	-
GDC 23	-
GDC 24	X
GDC 25	-
GDC 26	-
GDC 27	-
GDC 28	-
GDC 29	-
GDC 30	-
GDC 33	-
GDC 34	-

TABLE 7.1-2.5
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR SAFETY RELATED DISPLAY INSTRUMENTS (1, 8)

(Sheet 2 of 4)

	ACCIDENT MONITORS
GDC 35	-
GDC 37	-
GDC 38	-
GDC 40	-
GDC 41	-
GDC 43	-
GDC 44	-
GDC 46	-
GDC 50	-
GDC 54	-
GDC 55	-
GDC 56	-
GDC 57	-
GDC 63	-
GDC 64	X
RG 1.6	-
RG 1.7	-
RG 1.11	X
RG 1.12(2)	-
RG 1.22	-
RG 1.29	X

TABLE 7.1-2.5
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR SAFETY RELATED DISPLAY INSTRUMENTS (1, 8)

(Sheet 3 of 4)

	ACCIDENT MONITORS
RG 1.30	X
RG 1.32	-
RG 1.45	-
RG 1.47	-
RG 1.53	X
RG 1.62	-
RG 1.63 (3)	
RG 1.67 (4)	
RG 1.68 (5)	
RG 1.70	X
RG 1.75	X
RG 1.78	-
RG 1.80 (5)	
RG 1.89	X
RG 1.95	-
RG 1.97	X
RG 1.100	X
RG 1.105	-
RG 1.116	-
RG 1.120 (6)	

TABLE 7.1-2.5
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR SAFETY RELATED DISPLAY INSTRUMENTS (1, 8)

(Sheet 4 of 4)

	ACCIDENT MONITORS
IEEE STD 279	-
IEEE STD 308	
IEEE STD 317 (3)	
IEEE STD 323	X
IEEE STD 336	X
IEEE STD 338	-
IEEE STD 344	X
IEEE STD 379	X
IEEE STD 384	X

Notes:

1. The scope of applicability is instrumentation.
2. Refer to FSAR Section 3.7B.4 and Appendix 1A(B).
3. Refer to FSAR Section 8.3.1.2.1 and Appendix 1A(B).
4. Refer to FSAR Section 3.9B.3.3. and Appendix 1A(B).
5. Refer to FSAR Section 14.2 and Appendix 1A(B).
6. Refer to FSAR Section9.5.1 and Appendix 1A(B).
7. Refer to FSAR Section 7.1.
8. X Signifies compliance as discussed or qualified in the FSAR Section referenced in Table 7.1-1.

   - Not applicable.

TABLE 7.1-2.6
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR OTHER INSTRUMENTATION SYSTEMS REQUIRED FOR SAFETY (1,7)

(Sheet 1 of 5)

	I & C POWER SUPPLY(3)	RHR ISOLATION VALVES	REFUELING INTERLOCKS(8)	ACCUMULATOR MO. VALVES	SWITCHOVER INJECTION TO RECIRCULATION	PROCESS & EFF RADIATION MONITORS	RCPB LEAK DETECTION	INTERLOCKS RCS PRESSURE CONTROL	FIRE PROTECTION(6)
GDC 1		X	-	X	X	X	X	-	-
GDC 2		X	-	X	X	X	X	X	-
GDC 3		X	-	X	X	X	X	X	-
GDC 4		X	-	X	X	X	X	X	-
GDC 5		X	-	X	X	X	X	X	-
GDC 10		X	-	-	-	-	-	-	-
GDC 12		-	-	-	-	-	-	-	-
GDC 13		X	-	X	X	X	X	X	-
GDC 15		X	-	-	-	-	-	X	-
GDC 19		X	-	X	X	X	X	X	-
GDC 20		-	-	-	-	-	-	-	-
GDC 21		-	-	-	-	-	-	-	-
GDC 22		-	-	-	-	-	-	-	-
GDC 23		-	-	-	-	-	-	-	-
GDC 24		X	-	X	X	X	X	X	-
GDC 25	-	-	-	-	-	-	-	-	-
GDC 26		-	-	-	-	-	-	-	-
GDC 27		-	-	-	-	-	-	-	-

TABLE 7.1-2.6
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR OTHER INSTRUMENTATION SYSTEMS REQUIRED FOR SAFETY (1,7)

(Sheet 2 of 5)

	I & C POWER SUPPLY(3)	RHR ISOLATION VALVES	REFUELING INTERLOCKS(8)	ACCUMULATOR MO. VALVES	SWITCHOVER INJECTION TO RECIRCULATION	PROCESS & EFF RADIATION MONITORS	RCPB LEAK DETECTION	INTERLOCKS RCS PRESSURE CONTROL	FIRE PROTECTION(6)
GDC 28		-	-	-	-	-	-	-	-
GDC 29		-	-	-	-	-	-	-	-
GDC 30		-	-	-	-	-	X	X	-
GDC 33		-	-	-	-	-	-	-	-
GDC 34		X	-	-	-	-	-	-	-
GDC 35		X	-	X	X	-	-	-	-
GDC 37	-	-	-	X	X	-	-	-	-
GDC 38	-	-	-	-	X	-	-	-	-
GDC 40	-	-	-	-	X	-	-	-	-
GDC 41		-	-	-	-	-	-	-	-
GDC 43		-	-	-	-	-	-	-	-
GDC 44		-	-	-	-	-	-	-	-
GDC 46		-	-	-	-	-	-	-	-
GDC 50		-	-	-	-	-	-	-	-
GDC 54		-	-	-	-	-	-	-	-
GDC 55		X	-	-	-	-	-	-	-
GDC 56		-	-	-	-	-	-	-	-

TABLE 7.1-2.6
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR OTHER INSTRUMENTATION SYSTEMS REQUIRED FOR SAFETY (1,7)

(Sheet 3 of 5)

	I & C POWER SUPPLY(3)	RHR ISOLATION VALVES	REFUELING INTERLOCKS(8)	ACCUMULATOR MO. VALVES	SWITCHOVER INJECTION TO RECIRCULATION	PROCESS & EFF RADIATION MONITORS	RCPB LEAK DETECTION	INTERLOCKS RCS PRESSURE CONTROL	FIRE PROTECTION(6)
GDC 57		-	-	-	-	-	-	-	-
GDC 63		-	-	-	-	X	-	-	-
GDC 64		-	-	-	-	X	-	-	-
RG 1.6		-	-	-	-	-	-	-	-
RG 1.7		-	-	-	-	-	-	-	-
RG 1.11		-	-	-	-	-	-	-	-
RG 1.12(2)									
RG 1.22		-	-	-	X	-	-	-	-
RG 1.29		X	-	X	X	X	X	-	-
RG 1.30		X	-	X	X	X	X	-	-
RG 1.32		-	-	-	-	-	-	-	-
RG 1.45		-	-	-	-	X	X	-	-
RG 1.47		-	-	-	X	-	-	-	-
RG 1.53		X	-	X	-	X	-	-	-
RG 1.62		-	-	-	-	-	-	-	-
RG 1.63(3)									

TABLE 7.1-2.6
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR OTHER INSTRUMENTATION SYSTEMS REQUIRED FOR SAFETY (1,7)

(Sheet 4 of 5)

	I & C POWER SUPPLY(3)	RHR ISOLATION VALVES	REFUELING INTERLOCKS(8)	ACCUMULATOR MO. VALVES	SWITCHOVER INJECTION TO RECIRCULATION	PROCESS & EFF RADIATION MONITORS	RCPB LEAK DETECTION	INTERLOCKS RCS PRESSURE CONTROL	FIRE PROTECTION(6)
RG 1.67(4)									
RG 1.68(5)									
RG 1.70		X	-	X	X	X	X	X	-
RG 1.73		-	-	X	-	-	-	-	-
RG 1.75		X	-	X	X	-	-	-	-
RG 1.78		-	-	-	-	-	-	-	-
RG 1.80(5)						78			
RG 1.89		X	-	X	X	X	-	-	-
RG 1.95		-	-	-	-	-	-	-	-
RG 1.97		-	-	X	X	X	-	-	-
RG 1.100		X	-	X	X	X	-	-	-
RG 1.105		X	-	X	X	X	-	-	-
RG 1.118		-	-	-	-	-	-	-	-
RG 1.120(6)						78			
IEEE STD 279		-	-	-	-	-	-	-	-
IEEE STD 308		-	-	-	-	-	-	-	-

TABLE 7.1-2.6
SAFETY RELATED INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR OTHER INSTRUMENTATION SYSTEMS REQUIRED FOR SAFETY (1,7)

(Sheet 5 of 5)

	I & C POWER SUPPLY(3)	RHR ISOLATION VALVES	REFUELING INTERLOCKS(8)	ACCUMULATOR MO. VALVES	SWITCHOVER INJECTION TO RECIRCULATION	PROCESS & EFF RADIATION MONITORS	RCPB LEAK DETECTION	INTERLOCKS RCS PRESSURE CONTROL	FIRE PROTECTION(6)
IEEE STD 317(3)									
IEEE STD 323		X	-	X	X	X	-	-	-
IEEE STD 336		X	-	X	X	X	X	-	-
IEEE STD 338		-	-	-	X	-	-	-	-
IEEE STD 344		X	-	X	X	X	-	-	-
IEEE STD 379		X	-	X	X	X	-	-	-
IEEE STD 384		X	-	X	X	X	-	-	-

Notes:

1. The scope of applicability is instrumentation & control.
2. Refer to FSAR Section 3.7B.4 and Appendix 1A(B).
3. Refer to FSAR Section 8.3.1.2.1 and Appendix 1A(B).
4. Refer to FSAR Section 3.9B.3.3. and Appendix 1A(B).
5. Refer to FSAR Section 14.2 and Appendix 1A(B).
6. Refer to FSAR Section 9.5.1 and Appendix 1A(B).
7. X Signifies compliance as discussed or qualified in the FSAR sections referenced in Table 7.1-1. - Not applicable.
8. Refer to FSAR Sections 7.6.3 and 9.1.4.

TABLE 7.1-2.7
INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR CONTROL SYSTEMS NOT REQUIRED FOR SAFETY (1,7)

(Sheet 1 of 4)

	NSSS CONTROL SYSTEMS	BOP CONTROL SYSTEMS
GDC 1	-	-
GDC 2	-	-
GDC 3	-	-
GDC 4	-	-
GDC 5	-	-
GDC 10	-	-
GDC 12	-	-
GDC 13	X	X
GDC 15	-	-
GDC 19	X	X
GDC 20	-	-
GDC 21	-	-
GDC 22	-	-
GDC 23	-	-
GDC 24	X	X
GDC 25	-	-
GDC 26	X	-
GDC 27	-	-
GDC 28	-	-
GDC 29	-	-
GDC 30	-	-
GDC 33	-	-

TABLE 7.1-2.7
INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR CONTROL SYSTEMS NOT REQUIRED FOR SAFETY (1,7)

(Sheet 2 of 4)

	NSSS CONTROL SYSTEMS	BOP CONTROL SYSTEMS
GDC 34	-	-
GDC 35	-	-
GDC 37	-	-
GDC 38	-	-
GDC 40	-	-
GDC 41	-	-
GDC 43	-	-
GDC 44	-	-
GDC 46	-	-
GDC 50	-	-
GDC 54	-	-
GDC 55	-	-
GDC 56	-	-
GDC 57	-	-
GDC 63	-	-
GDC 64	-	-
RG 1.6	-	-
RG 1.7	-	-
RG 1.11	-	-
RG 1.12(2)		
RG 1.22	-	-

TABLE 7.1-2.7
INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR CONTROL SYSTEMS NOT REQUIRED FOR SAFETY (1,7)

(Sheet 3 of 4)

	NSSS CONTROL SYSTEMS	BOP CONTROL SYSTEMS
RG 1.29	-	-
RG 1.30	-	-
RG 1.32	-	-
RG 1.45	-	-
RG 1.47	-	-
RG 1.53	-	-
RG 1.62	-	-
RG 1.63(3)		
RG 1.67(4H4)		
RG 1.68(5)		
RG 1.70	X	X
RG 1.75	-	-
RG 1.78	-	-
RG 1.80(5)		
RG 1.89	-	-
RG 1.95	-	-
RG 1.97	-	-
RG 1.100	-	-
RG 1.105	-	-
RG 1.118	-	-
RG 1.120(6)		

TABLE 7.1-2.7
INSTRUMENTATION & CONTROL SYSTEMS/CODES, STANDARDS & GUIDES/APPLICABILITY MATRIX FOR CONTROL SYSTEMS NOT REQUIRED FOR SAFETY (1,7)

(Sheet 4 of 4)

	NSSS CONTROL SYSTEMS	BOP CONTROL SYSTEMS
IEEE STD 279[8]	X	-
IEEE STD 308	-	-
IEEE STD 317[3]		
IEEE STD 323	-	-
IEEE STD 336	-	
IEEE STD 338	-	-
IEEE STD 344	-	-
IEEE STD 379	-	-
IEEE STD 384	-	-

Notes:

1. The scope of applicability is instrumentation & control.
2. Refer to FSAR Section 3.7B.4 and Appendix 1A(B).
3. Refer to FSAR Section 8.3.1.2.1 and Appendix 1A(B).
4. Refer to FSAR Section 3.9B.3.3. and Appendix 1A(B).
5. Refer to FSAR Section 14.2 and Appendix 1A(B).
6. Refer to FSAR Section 9.5.1 and Appendix 1A(B).
7. X Signifies compliance as discussed or qualified in the FSAR Sections referenced in Table 7.1-1.

   - Not applicable.
8. Compliance with Paragraph 4.7 of IEEE Std. 279, Control and Protection System Interaction.

TABLE 7.1-3
EICSB BRANCH TECHNICAL POSITIONS

(Sheet 1 of 2)

Criteria	Title	Information Related to Conformance Discussed In:
BTP EICSB-1	Backfitting of the Protection and Emergency Power Systems of Nuclear Reactors	Not Applicable
BTP EICSB-3	Isolation of Low Pressure Systems From the High Pressure Reactor Coolant System	5.4.7.2.4, 7.6.2
BTP EICSB-4 (PSB)	Requirements on Motor-Operated Valves in the ECCS Accumulator Lines	6.3.1, 6.3.2, 7.6
BTP EICSB-5	Scram Breaker Test Requirements - Technical Specifications	7.2.2.2.3.10
BTP EICSB-9	Definition and Use of “Channel - Calibration” - Technical Specifications	7.2.2.2.3.10
BTP EICSB-10	Electrical and Mechanical Equipment Seismic Qualification Program	See RG 1.100, 3.10(N), 3.10(B), 1A(N), 1A(B)
BTP EICSB-12	Protection System Trip Point Changes for Operation with Reactor Coolant Pumps Out of Service	7.2.2.2.1,
BTP EICSB-13	Design Criteria for Auxiliary Feedwater Systems	10.4.9, Table 10.4-9
BTP EICSB-14	Spurious Withdrawals of Single Control Rods in Pressurized Water Reactors	3.1.3.1, 3.1.3.6, Chapter 15, 7.7.2.2
BTP EICSB-15(PSB)	Reactor Coolant Pump Breaker Qualifications	7.2.1.1.2.4, 8.3.1.1.2, 15.3, 5.4, 15.2, 7.1.2.5
BTP EICSB-16	Control Element Assembly (CEA) Interlocks in Combustion Engineering Reactors	Not Applicable

TABLE 7.1-3
EICSB BRANCH TECHNICAL POSITIONS

(Sheet 2 of 2)

Criteria	Title	Information Related to Conformance Discussed In:
BTP EICSB-18	Application of the Single Failure Criteria to Manually-Controlled Electrically-Operated Valves	6.2.4.1.3, 6.3.1, 6.3.2.2.12, 6.3.2.5, 6.3.5.5, 7.6.4
BTP EICSB-19	Acceptability of Design Criteria for Hydrogen Mixing and Drywell Vacuum Relief Systems	Not Applicable
BTP EICSB-20	Design of Instrumentation and Controls Provided to Accomplish Changeover from Injection to Recirculation Mode	7.6.5, 6.3.2.8, Table 6.3-7
BTP EICSB-21	Guidance for Application of Regulatory Guide 1.47	7.1.2.6
BTP EICSB-22	Guidance for Application of Regulatory Guide 1.22	7.1.2.5
BTP EICSB-23	Qualification of Safety-Related Display Instrumentation for Post-Accident Condition Monitoring and Safe Shutdown	7.5
BTP EICSB-24	Testing of Reactor Trip System and Engineered Safety Feature Actuation System Sensor Response Times	7.1.2.11
BTP EICSB-25	Guidance for the Interpretation of General Design Criterion 37 for Testing the Operability of the Emergency Core Cooling System as a Whole	3.1, 6.3.4
BTP EICSB-26	Requirements for Reactor Protection System Anticipatory Trips	7.2.1.1.2.(6)
BTP EICSB-27	Design Criteria for Thermal Overload Protection for Motors of Motor-Operated Valves	8.3.1.2

7.2 REACTOR AND TRIP SYSTEM

7.2.1 DESCRIPTION

7.2.1.1 System Description

The Reactor Trip System (RTS) automatically keeps the reactor operating within a safe region by shutting down the reactor whenever the limits of the region are approached. The safe operating region is defined by several considerations such as mechanical/hydraulic limitations on equipment, and heat transfer phenomena. Therefore the RTS keeps surveillance on process variables which are directly related to equipment mechanical limitations, such as pressure, pressurizer water level (to prevent water discharge through safety valves, and uncovering heaters) and also on variables which directly affect the heat transfer capability of the reactor (e.g., flow and reactor coolant temperatures). Still other parameters utilized in the RTS are calculated from various process variables. In any event, whenever a direct process or calculated variable exceeds a setpoint the reactor will be shutdown in order to protect against either gross damage to fuel cladding or loss of system integrity which could lead to release of radioactive fission products into the Containment.

The following systems make up the RTS (see References [1], [2], [3], and [5] for additional background information).

1. Process Instrumentation and Control System.

2. Nuclear Instrumentation System.

3. Solid State Logic Protection System.

4. Reactor trip switchgear.

5. Manual actuation circuit.

The RTS consists of sensors which, when connected with analog circuitry consisting of two to four redundant channels monitor various plant parameters, and digital circuitry, consisting of two redundant logic trains, which receives inputs from the analog protection channels to complete the logic necessary to automatically open the reactor trip breakers.

Each of the two trains, A and B, is capable of opening a separate and independent reactor trip breaker, RTA and RTB, respectively. The two trip breakers in series connect three phase alternating current (AC) power from the rod drive motor generator sets to the rod drive power cabinets, as shown on Figure 7.2-1, Sheet 2. During plant power operation, a direct current (DC) undervoltage coil on each reactor trip breaker holds a trip plunger against its spring, allowing the power to be available at the rod control power supply cabinets. For reactor trip, a loss of DC voltage to the undervoltage coil releases the trip plunger and trips open the breaker. When either of the trip breakers opens, power is interrupted to the rod drive power supply, and the control rods fall, by gravity, into the core. The rods cannot be withdrawn until the trip breakers are manually reset. The trip breakers cannot be reset until the abnormal condition which initiated the trip is corrected. Bypass breakers BYA and BYB are provided to permit testing of the trip breakers, as discussed in Section 7.2.2.2.3.

7.2.1.1.1 Functional Performance Requirements

The RTS automatically initiates reactor trip:

1. Whenever necessary to prevent fuel damage for an anticipated operational transient (Condition II).

2. To limit core damage for infrequent faults (Condition III),

3. So that the energy generated in the core is compatible with the design provisions to protect the reactor coolant pressure boundary for limiting fault conditions (Condition IV).

The RTS initiates a turbine trip signal whenever reactor trip is initiated to prevent the reactivity insertion that would otherwise result from excessive reactor system cooldown to avoid unnecessary actuation of the Engineered Safety Features Actuation System.

The RTS provides for manual initiation of reactor trip by operator action.

7.2.1.1.2 Reactor Trips

The various reactor trip circuits automatically open the reactor trip breakers whenever a condition monitored by the RTS reaches a preset level. To ensure a reliable system, high quality design, components, manufacturing, quality control and testing is used. In addition to redundant channels and trains, the design approach provides a RTS which monitors numerous system variables, therefore providing protection system functional diversity. The extent of this diversity has been evaluated for a wide variety of postulated accidents.

Table 7.2-1 provides a list of reactor trips which are described below.

1. Nuclear overpower trips

   The specific trip functions generated are as follows:

   a. Power range high neutron flux trip

      The power range high neutron flux trip circuit trips the reactor when two out of the four power range channels exceed the trip setpoint.

      There are two bistables, each with its own trip setting used for a high and a low range trip setting. The high trip setting provides protection during normal power operation and is always active. The low trip setting, which provides protection during startup, can be manually bypassed when two out of the four power range channels read above approximately 10 percent power (P-10). Three out of the four channels below 10 percent automatically reinstate the trip function. Refer to Table 7.2-2 for a listing of all protection system interlocks.

   b. Intermediate range high neutron flux trip

      The intermediate range high neutron flux trip circuit trips the reactor when one out of the two intermediate range channels exceed the trip setpoint. This trip, which

provides protection during reactor startup, can be manually blocked if two out of four power range channels are above approximately 10 percent power (P-10). Three out of the four power range channels below this value automatically reinstate the intermediate range high neutron flux trip. The intermediate range channels (including detectors) are separate from the power range channels. The intermediate range channels can be in-bypassed at the nuclear instrumentation racks to permit channel testing during plant shutdown or prior to startup. This bypass action is annunciated on the control board.

c. Source range high neutron flux trip

The source range high neutron flux trip circuit trips the reactor when one out of the two source range channels exceeds the trip setpoint. This trip, which provides protection during reactor startup and plant shutdown, can be manually bypassed when one out of the two intermediate range channels reads above the P-6 setpoint value and is automatically reinstated when both intermediate range channels decrease below the P-6 setpoint value. This trip is also automatically bypassed by two out of four logic from the power range protection interlock (P-10). This trip function can also be reinstated below P-10 by an administrative action requiring manual actuation of two control board mounted switches. Each switch will reinstate the trip function in one out of the two protection logic trains. The source range trip point is set between the P-6 setpoint (source range cutoff power level) and the maximum source range power level. The channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during plant shutdown or prior to startup. This bypass action is annunciated on the control board.

d. Power range high positive neutron flux rate trip

This circuit trips the reactor when a sudden abnormal increase in nuclear power occurs in two out of four power range channels. This trip provides protection against uncontrolled RCCA bank withdrawal and rod ejection accidents of low worth from midpower and is always active.

Figure 7.2-1, Sheet 3, shows the logic for all of the nuclear overpower and positive rate trips.

2. Core thermal overpower trips

The N-16 system installed at CPNPP provides protection equivalent to that of over-power ΔT protection assumed in WCAP-9227 (Reference 5 of 15.1).

In addition to the specific trip functions generated, as discussed in the following subsections, a spectrum of steam line break accidents were analyzed to determine any part of the spectrum in which protection from thermal overpower trips (overpower or overtemperature N-16) might be required. Based on this analysis, it was determined that thermal overpower trips would be required to function for a range of small to intermediate size steam line breaks. Calculation of the containment pressure and temperature transients associated with this range of steam line breaks shows that the maximum containment temperature for which the thermal overpower trips will be required is 200°F.

If the containment temperature exceeds 200°F, a high containment pressure safety injection and reactor trip signal will be actuated, and the thermal overpower instrumentation will not be required. Thus, 200°F has been established as the maximum qualification temperature required for the N-16 detectors which feed into the thermal overpower trips.

The basis for the equations for the Overtemperature and Overpower setpoints can be understood by examining Figure 15.0-1 in Chapter 15. The Overpower and Overtemperature N-16 protection limits are established such that these two trips, in conjunction with the High and Low Pressurizer Pressure reactor trips and the steam generator safety valve limits, will provide protection against exceeding the core thermal limits. These trips are equivalent to the Overpower and Overtemperature ΔT trips, using N-16 as a power measurement rather than ΔT, and using T_{avg} as a combination of N-16 and T_{cold} rather than a combination of T_{hot} and T_{cold} as in the $\Delta T/T_{avg}$ design.

The specific trip functions generated are as follows:

a. Overtemperature N-16 trip

This trip protects the core against low DNBR and trips the reactor on coincidence as listed in Table 7.2-1 with one set of temperature measurements per loop. The setpoint for this trip is continuously calculated by analog circuitry for each loop by solving the following equation:

$$Q_{setpoint} = K_1 - K_2 \frac{(1+\tau_1 S)}{(1+\tau_2 S)} (T_{cold} - T°cold) + K_3(P - 2235) - f_1(\Delta\varphi)$$

Where:

T_{cold}	=	Measured value of Cold Leg Temperature (°F)
T°cold	=	indicated T_{cold} at rated thermal power
P	=	pressurizer pressure (psig)
K_1	=	preset bias
K_2	=	preset gain which compensates for the effect of temperature on the DNB limits
K_3	=	preset gain which compensates for the effect of pressure on the DNB limits
τ_1, τ_2	=	preset constants which compensate for piping and instrument time delay

S	=	laplace transform operator (seconds^{-1})
$f_1(\Delta\phi)$	=	a function of the neutron flux difference between average of the upper two and average of the lower two calibrated ion chambers readings (refer to Figure 7.2-2)

A separate ion chamber unit supplies the flux signal for each Overtemperature N-16 trip channel.

The basis for the Overtemperature N-16 is to prevent exceeding the DNB limits. As shown in Figure 15.0-1, for a given flow rate and power distribution, these limits are a function of T_{cold} and pressure; hence the Overtemperature N-16 setpoint equation is a function of T_{cold} and pressure. Dynamic compensation terms are included to account for the response time of the T_{cold} measurement. The $f_1(\Delta\phi)$ term is used to reduce the trip setpoint to account for the effects of axial power distributions more severe than the design values illustrated in Figure 15.0-1. Again, this is the same basis and same form of setpoint equations as the Overtemperature ΔT trip.

Increases in $f_1(\Delta\phi)$ beyond a pre-defined deadband result in a decrease in trip setpoint. Refer to Figure 7.2-2.

The required one pressurizer pressure parameter per loop is obtained from separate sensors connected to three pressure taps at the top of the pressurizer. Four pressurizer pressure signals are obtained from the three taps by connecting one of the taps to two pressure transmitters. Refer to Section 7.2.2.3.3 for an analysis of this arrangement.

Figure 7.2-1, Sheet 5, shows the logic for Overtemperature N-16 trip function.

The actual core power, which is used for comparison to the trip setpoint described above, is measured with an N-16 power meter as described in reference 5. There is one power meter on each loop. Figure 7.7-18 shows the complete functional diagram of the Comanche Peak N-16 system, including all compensation terms.

Some minor differences exist between the Comanche Peak N-16 system and that described in WCAP-9190 as described below. The functional diagram given in WCAP-9190 applies to a digital system while that given for Comanche Peak (Figure 7.7-18) applies to an analog system. The Comanche Peak system contains a temperature compensation term not contained in WCAP-9190. Finally, the N-16 system in WCAP-9190 contains a background radiation compensation term which is not in the N-16 system given herein. This compensation is only required if significant fuel failures exists, as discussed in WCAP-9190. If fuel failures should occur during operation, the N-16 power meter will read high which means the trip point will be reached earlier than required. Thus, the plant is always protected.

b. Overpower N-16 trip

This trip protects against excessive power (fuel rod rating protection) and trips the reactor on coincidence as listed in Table 7.2-1, with one set of temperature measurements per loop. The setpoint for each channel is continuously calculated using the following equation:

$$Q \text{ setpoint} = K_4 - f_2(\Delta\phi)$$

Where

$f_2(\Delta\phi)$ = a function of the neutron flux difference between the average of the upper two and average of the lower two calibrated ion chamber current readings. However, $f_2(\Delta\phi)=0$.

K_4 = A preset bias

The source of flux information is identical to that of the Overtemperature N-16 trip and the resultant Q setpoint is compared to the same Q. Figure 7.2-1, Sheet 5, shows the logic for this trip function.

The basis for the Overpower N-16 trip is to prevent the core thermal power from exceeding 118% of rated power consistent with the design basis discussed in Sections 4.4.2.11.6 and 4.3.2.2.6. This basis is the same as for the Overpower ΔT setpoint although the resulting equation is somewhat simpler due to the direct measurement of power. (For the ΔT equation, additional terms are required to account for the change in the heat capacity of water with temperature and for the relatively longer measurement time response associated with the T_{avg} and ΔT measurements.) The $f_2(\Delta\phi)$ term was retained, identical to the Overpower ΔT setpoint, to allow the capability for dealing with severe axial power distributions.

3. Reactor Coolant System pressurizer pressure and water level trips

The specific trip functions generated are as follows:

a. Pressurizer low pressure trip

The purpose of this trip is to protect against low pressure which could lead to DNB. The parameter being sensed is reactor coolant pressure as measured in the pressurizer. Above P-7 the reactor is tripped when the pressurizer pressure measurements (compensated for rate of change) fall below preset limits. This trip is blocked below P-7 to permit startup. The trip logic and interlocks are given in Table 7.2-1.

The trip logic is shown on Figure 7.2-1, Sheet 6.

b. Pressurizer high pressure trip

The purpose of this trip is to protect the Reactor Coolant System against system overpressure.

The same sensors and transmitters used for the pressurizer low pressure trip are used for the high pressure trip except that separate bistables are used for trip. These bistables trip when uncompensated pressurizer pressure signals exceed preset limits on coincidence as listed in Table 7.2-1. There are no interlocks or permissives associated with this trip function.

The logic for this trip is shown on Figure 7.2-1, Sheet 6.

c. Pressurizer high water level trip

This trip is provided as a back-up to the high pressurizer pressure trip and serves to prevent water relief through the pressurizer safety valves. This trip is blocked below P-7 to permit startup. The coincidence logic and interlocks of pressurizer high water level signals are given in Table 7.2-1.

The trip logic for this function is shown on Figure 7.2-1, Sheet 6.

4. Reactor Coolant System low flow trips

These trips protect the core from DNB in the event of a loss of coolant flow situation. Figure 7.2-1, Sheet 5, shows the logic for these trips. The means of sensing the loss of coolant flow are as follows:

a. Low reactor coolant flow

Reactor coolant flow is sensed by three differential pressure transmitters which are connected to a network of four elbow taps in each coolant loop. Each transmitter provides a signal to a low flow bistable. A trip signal from two out of three bistables indicates a low flow in the loop.

The coincidence logic and interlocks are given in Table 7.2-1.

b. Reactor coolant pump undervoltage trip (BOP Scope)

This trip is required in order to protect against low flow which can result from loss of voltage to more than one reactor coolant pump motor (e.g., from plant blackout or reactor coolant pump breakers opening).

There is one undervoltage sensing relay connected for each pump at the motor side of each reactor coolant pump breaker. These relays provide an output signal when the pump voltage goes below approximately 70 percent of rated voltage. Signals from these relays are time delayed to prevent spurious trips caused by short term voltage perturbations. The coincidence logic and interlocks are given in Table 7.2-1.

c. Reactor coolant pump underfrequency trip (BOP Scope)

This trip protects against low flow resulting from pump underfrequency, for example a major power grid frequency disturbance. The function of this trip is to trip the reactor for an underfrequency condition greater than approximately 2.4 hertz (Hz)/ second. The setpoint of the underfrequency relays is adjustable between 54 and 59 Hz.

There is one underfrequency sensing relay for each reactor coolant pump motor. Signals from relays for any two of the pump motors (time delayed up to approximately 0.1 second to prevent spurious trips caused by short term frequency perturbations) will trip the reactor if the power level is above P-7.

Undervoltage, underfrequency and associated time delay relays for the four channels are housed in a protection relay rack. The protection relay rack is divided into four separate compartments, similar to the Solid State Protection System input cabinet described in Section 7.1.2.3 to maintain channel independence. Potential transformers from which the input signals for undervoltage and underfrequency relays are derived and the protection relay rack are classified as Class 1E and are located in a Seismic Category I structure.

5. Steam generator trip/Low-low steam generator water level trip

The specific trip function generated is the low-low steam generator water level trip. This trip protects the reactor from loss of heat sink in the event of a loss of feedwater to the steam generators. This trip is actuated on two out of four low-low water level signals occurring in any steam generator.

The logic is shown on Figure 7.2-1, Sheet 7.

6. Reactor trip on a turbine trip (anticipatory) (BOP Scope)

The reactor trip on a turbine trip is actuated by two out of three logic from emergency trip fluid pressure signals or by all closed signals from the turbine steam stop valves. A turbine trip causes a direct reactor trip above P-9. The reactor trip on turbine trip provides additional protection and conservatism beyond that required for the health and safety of the public. This trip is included as part of good engineering practice and prudent design. Though the trip is non-safety related, calibration and maintenance of the associated hardware is subject to an operational QA program. No credit is taken in any of the safety analyses (Chapter 15) for this trip.

The turbine provides anticipatory trips to the Reactor Protection System from contacts which change position when the turbine stop valves close or when the turbine emergency trip fluid pressure goes below its setpoint.

The turbine trip fluid pressure switches and turbine stop valve closed limit switches are procured as Class 1E. Seismic qualification is not required as described herein. Wiring from these switches in the turbine building to the reactor protection system cabinets is routed in accordance with the same separation criteria, applicable to protection

channels I, II, III and IV and is in rigid steel conduits dedicated exclusively for these signals. These conduits are shown on plant physical layout drawings.

The reactor trip system interfaces with the turbine trip system as shown on Figure 7.2-1, sheet 16. The turbine trip fluid is dumped by non-Class 1E turbine trip solenoid valves. The reactor trip system is separated and isolated from the non-Class 1E main turbine trip solenoids by Class 1E isolation devices, typically described in Section 8.3.1.2.1 subparagraph b.1.

One of the design bases considered in the Protection System is the possibility of an earthquake. With respect to these contacts, their functioning is unrelated to a seismic event in that they are anticipatory to other diverse parameters which cause reactor trip. The contacts are shut during plant operation and open to cause reactor trip when the turbine is tripped. No power is provided to the Protection System from the contacts; they merely serve to interrupt power to cause reactor trip. This design functions in a de-energize-to-trip fashion to cause a plant trip if power is interrupted in the trip circuitry. This ensures that the Protection System will in no way be degraded by this anticipatory trip because seismic design considerations do not form part of the design bases for anticipatory trip sensors. (The Reactor Protection System cabinets which receive the inputs from the anticipatory trip sensors are, of course, seismically qualified as discussed in Section 3.10N.) The anticipatory trips thus meet the Institute of Electrical and Electronic Engineers (IEEE) Standard 279-1971, including redundancy, separation, single failure, etc. Seismic qualification of the contacts sensors is not required.

The logic for this trip is shown on Figure 7.2-1, Sheet 16.

7. Safety injection signal actuation trip

A reactor trip occurs when the Safety Injection System is actuated. The means of actuating the Safety Injection System are described in Section 7.3. This trip protects the core against any event which would actuate safety injection.

Figure 7.2-1, Sheet 8, shows the logic for this trip.

8. Manual Trip

The manual trip consists of two switches with two outputs on each switch. One output is used to actuate the train A trip breaker, the other output actuates the train B trip breaker. Operation of either switch de-energizes the undervoltage coils in both breakers through both logic trains. At the same time the breaker shunt coils in both breakers are energized. Figure 7.2-3 shows the switch arrangement and Figure 7.2-1 Sheet 3 shows the manual trip logic. There are no interlocks which can block this trip.

The bases for this design are in Regulatory Guide 1.62 and single failure criteria of IEEE-279 and IEEE-379. It provides that either switch will initiate the required action at the system level (both trains). Failure of one switch will not prevent system actuation to open both reactor trip breakers.

In order to maintain separation between wiring associated with different trains, redundant safety train wiring is not terminated on a single device. Backup manual actuation

switches link the separate trains by mechanical means to provide greater reliability of operator action for the manual reactor trip (as well as Engineered Safety Features actuations). The linked switches are themselves redundant so that operation of either set of linked switches will actuate safety trains “A” and “B” simultaneously.

7.2.1.1.3 Reactor Trip System Interlocks

1. Power escalation permissivies

The overpower protection provided by the out of core nuclear instrumentation consists of three discrete, but overlapping, ranges. Continuation of startup operation or power increase requires a permissive signal from the higher range instrumentation channels before the lower range level trips can be manually blocked by the operator.

A one out of two intermediate range permissive signal (P-6) is required prior to source range trip blocking and detector high voltage cutoff. Source range trips are automatically reactivated and high voltage restored when both intermediate range channels are below the permissive (P-6) setpoint. There are two manual reset switches for administratively reactivating the source range level trip and detector high voltage when between the permissive P-6 and P-10 set points, if required. Source range level trip block and high voltage cutoff are always maintained when above the permissive P-10 setpoint.

The intermediate range level trip and power range (low setpoint) trip can only be blocked after satisfactory operation and permissive information are obtained from two out of four power range channels. Four individual blocking switches are provided so that the low range power range trip and intermediate range trip can be independently blocked (one switch for each train). These trips are automatically reactivated when any three out of four power range channels are below the permissive (P-10) setpoint, thus ensuring automatic activation to more restrictive trip protection.

The development of permissives P-6 and P-10 is shown on Figure 7.2-1, Sheet 4. All of the permissives are digital; they are derived from analog signals in the nuclear power range and intermediate range channels.

Refer to Table 7.2-2 for the list of Protection System interlocks.

2. Blocks of reactor trips at low power

Interlock P-7 blocks a reactor trip at low power (below approximately 10 percent of full power) on a low reactor coolant flow in more than one loop, reactor coolant pump undervoltage, reactor coolant pump underfrequency, pressurizer low pressure or pressurizer high water level. Refer to Figure 7.2-1, Sheets 5 and 6 for permissive applications. The low power signal is derived from three out of four power range neutron flux signals below the setpoint in coincidence with two out of two turbine impulse chamber pressure signals below the setpoint (low plant load). See Figure 7.2-1, Sheets 4 and 16, for the derivation of P-7.

The P-8 interlock blocks a reactor trip when the plant is below approximately 48 percent of full power, on a low reactor coolant flow in any one loop. The block action (absence of the interlock signal) occurs when three out of four neutron flux power range signals are

below the setpoint. Thus, below the P-8 setpoint, the reactor will be allowed to operate with one inactive loop and trip will not occur until two loops are indicating low flow. Refer to Figure 7.2-1, Sheet 4, for derivation of P-8, and Sheet 5 for applicable logic.

The P-9 interlock blocks a reactor trip following a turbine trip when the plant is below approximately 50% of full power. The plant is designed for 50% load rejection capability (40% steam dump and 10% control rods insertion). The absence of the P-9 interlock (three out of four power range flux signals below the setpoint) blocks the immediate reactor trip following a turbine trip. Refer to Figure 7.2-1, Sh. 4 for derivation of P-9 and Sh. 16 for applicable logic.

Refer to Table 7.2-2 for the list of Protection System blocks.

7.2.1.1.4 Coolant Temperature, N-16 and Power Range Neutron Detector Sensor Arrangement

The bypass line T_{hot} and T_{cold} measurements are, as a result of incorporation of the Comanche Peak Protection and Surveillance Upgrade Package, being replaced with an N-16 power monitor and an in-line T_{cold} measurement. In addition, the present two-section power range neutron detectors are being replaced with four-section detectors (used for both protection and control functions).

7.2.1.1.4.1 In-Line Fast Response Thermowell Installation of Cold Leg Temperature Measurement

The fast response in-line T_{cold} measurement is provided by an RTD in a thin wall thermowell installed in the reactor coolant cold leg piping. The thin-wall thermowell is designed to provide improved time response for a T_{cold} measurement which uses a thermowell installation. The system includes two cold leg RTD's per loop, one active RTD and one installed spare, both wired to the process protection cabinet. Utilization of thermowells allows replacement of the RTD's without violating the reactor coolant boundary.

The cold leg bypass nozzles, and crossover leg bypass return nozzles were installed in the Comanche Peak reactor coolant system piping; however, all of these connections have been plugged and are not used.

7.2.1.1.4.2 N-16 Sensor Arrangement

The N-16 power monitor (see Reference 5) measures the thermal power of the NSSS by detecting the amount of N-16 present in the coolant system. The N-16 population (an isotope of the nitrogen generated by neutron activation of oxygen contained in the water) which is present in the primary coolant is directly proportional to the fission rate in the core. Decay of the N-16 isotope produces high-energy gamma rays which penetrate the wall of the high-pressure piping. As a result, the N-16 concentration in the primary coolant can be monitored by measuring the gamma radiation outside of the primary coolant piping.

The N-16 gamma radiation is detected by ion chambers located on the hot leg piping of each coolant loop. Detectors are mounted on opposite sides of the hot leg so that asymmetries due to geometry effects can be compensated for the measured N-16.

A total of four N-16 gamma detectors and mounting assemblies are provided for each loop and will be strapped on the RC piping. All four are mounted on the hot leg outside the biological shield and as close to the reactor vessel as possible.

An N-16 Transit Time Flow Meter (TTFM) is also included in the upgrade package. The removal of the RTD bypass lines requires that an alternative method of flow verification measurement be provided during plant startup and periodically (once per cycle) throughout plant life. The TTFM is portable and not connected to the N-16 detectors during normal operation; therefore, it is normally independent from the protection equipment. Interface by plug-in connectors is made only at the time of flow calibration. The N-16 TTFM performance data will be collected during the first cycle of CPNPP Unit 1 for review and evaluation. This data will be submitted to the NRC to further support the uncertainty analysis of the N-16 TTFM.

The N-16 Flow Measurement System allows the use of the two N-16 power monitor detectors, in conjunction with two additional N-16 detectors, to verify the flow in each of the reactor coolant loops to an improved flow calibration accuracy. Thus four N-16 detectors per loop are used for flow measurement, with two of the four per loop also being used for power measurements.

Since the N-16 detectors are externally mounted on the reactor coolant system piping, no loop penetrations are required. This system requires no flow calibration and introduces no pressure drop. Therefore, no primary system changes are needed. The system requires only the availability of containment penetrations to connect the detector output to an electronics rack in the control room.

To check the flow in any loop, a portable N-16 TTFM electronic rack would be positioned at the appropriate N-16 power monitor channel and connected to the gamma detectors by means of an interface panel located in an upgrade protection cabinet. Prior to connection of the TTFM, all of the bistables associated with that N-16 power monitor channel would be put in the tripped or bypass mode (as is done for test purposes) to preclude any control (TTFM) and protection (N-16 power) interaction. The TTFM utilizes the detectors of the N-16 power monitor.

The Transit Time Flow Meter (TTFM) accurately measures the reactor coolant primary loop flow by sensing the radioactive signature of the N-16 isotope. Cross-correlation techniques are used to determine the mean transit time of the N-16 signature from an upstream to a downstream detector. By knowing the distance between the detectors, the measured transit time, and the piping internal diameter, the volumetric flow in each coolant loop can be determined. This direct conversion of N-16 activity to RCS flow is accomplished with an accuracy of $\pm$ 1.3 percent. For additional conservatism, the Technical Specifications state an accuracy value of $\pm$ 1.8 percent.

7.2.1.1.4.3 Power Range Neutron Detector Assembly Installation

Four-section power range neutron detector assemblies (four sets) are provided to replace the two-section detectors and mount in the existing detector assembly.

Each of the four-section power range detector assemblies is supplied with a junction box (mounted outside the biological shield) for distribution of the common high voltage to each of the four sections. A similar junction box is supplied for each set of four N-16 detectors (mounted in the hot leg area).

7.2.1.1.5 Pressurizer Water Level Reference Leg Arrangement

The design of the pressurizer water level instrumentation employs the usual tank level arrangement using differential pressure between an upper and a lower tap on a column of water. A reference leg connected to the upper tap is kept full of water by condensation of steam at the top of the leg.

7.2.1.1.6 Analog System

The analog system consists of two instrumentation systems: the Process Instrumentation System and the Nuclear Instrumentation System.

Process instrumentation includes those devices (and their interconnection into systems) which measure temperature, pressure, fluid flow, fluid level as in tanks or vessels, and occasionally physiochemical parameters such as fluid conductivity or chemical concentration. Process instrumentation specifically excludes nuclear and radiation measurements. The process instrumentation includes the process measuring devices, power supplies, indicators, recorders, alarm actuating devices, controllers, signal conditioning devices, etc., which are necessary for day-to-day operation of the Nuclear Steam Supply System as well as for monitoring the plant and providing initiation of protective functions upon approach to unsafe plant conditions.

The primary function of nuclear instrumentation is to protect the reactor by monitoring the neutron flux and generating appropriate trips and alarms for various phases of reactor operating and shutdown conditions. It also provides a secondary control function and indicates reactor status during startup and power operation. The Nuclear Instrumentation System uses information from three separate types of instrumentation channels to provide three discrete protection levels. Each range of instrumentation (source, intermediate, and power) provides the necessary overpower reactor trip protection required during operation in that range. The overlap of instrument ranges provides reliable continuous protection beginning with source level through the intermediate and low power level. As the reactor power increases, the overpower protection level is increased by administrative procedures after satisfactory higher range instrumentation operation is obtained. Automatic reset to more restrictive trip protection is provided when reducing power.

Various types of neutron detectors, with appropriate solid state electronic circuitry, are used to monitor the leakage neutron flux from a completely shutdown condition to 120 percent of full power. The power range channels are capable of recording overpower excursions up to 200 percent of full power. The neutron flux covers a wide range between these extremes. Therefore, monitoring with several ranges of instrumentation is necessary.

The lowest range (“source” range) covers six decades of leakage neutron flux. The lowest observed count rate depends on the strength of the neutron sources in the core and the core multiplication associated with the shutdown reactivity. This is generally greater than two counts per seconds. The next range (“intermediate” range) covers eight decades. Detectors and instrumentation are chosen to provide overlap between the higher portion of the source range and the lower portion of the intermediate range. The highest range of instrumentation (“power” range) covers approximately two decades of the total instrumentation range. This is a linear range that overlaps with the higher portion of the intermediate range.

The system described above provides control room indication and recording of signals proportional to reactor neutron flux during core loading, shutdown, startup and power operation, as well as during subsequent refueling. Startup rate indication for the source and intermediate range channels is provided at the control board. Reactor trip, rod stop, control and alarm signals are transmitted to the Reactor Control and Protection System for automatic plant control. Equipment failures and test status information are annunciated in the control room.

Refer to References [1] and [2] for additional background information on the process and nuclear instrumentation.

7.2.1.1.7 Solid State Logic Protection System

The Solid State Logic Protection System takes binary inputs (voltage/no voltage) from the process and nuclear instrument channels corresponding to conditions (normal/abnormal) of plant parameters. The system combines these signals in the required logic combination and generates a trip signal (no voltage) to the undervoltage coils of the reactor trip circuit breakers when the necessary combination of signals occur. The system also provides annunciator, status light and computer input signals which indicate the condition of bistable input signals, partial trip and full trip functions and the status of the various blocking, permissive and actuation functions. Refer to Reference [3] for additional background information.

In addition the system includes means for semiautomatic testing of the logic circuits.

Problems have been experienced by other operating nuclear power plants in the testing of the solid state protection system. The problems identified include failure of the automatic test equipment to test the integrated circuit ZIC (a NAND gate in the scram breaker undervoltage card), an isolation problem in the general warning circuit, and the use of diodes with insufficient voltage rating. Though these problems appear to be different, they all relate to the same concern; in this case, an undetectable failure in the General Warning Alarm reactor trip circuits in the Solid State Protection System. The consequences of the failure were reported by the individual operating plant, but independent reporters have produced different descriptions of the same thing. Westinghouse assessed the incident, reported the generic impact to the NRC, and submitted for approval circuit modifications to resolve the deficiency. NRC Inspection and Enforcements witnessed verification tests which Westinghouse conducted after receipt of NRC acceptance (see Reference [6]). These changes have been implemented in the System for CPNPP, and are confirmed and documented in accordance with established Westinghouse PWR OA procedures.

The NRC has also indentified another potential problem, which has been found at other operating plants, and that is the modification of previously qualified components during production by their vendors which upon modification could not satisfy the original functional-requirements. Such a modification was found to have occurred at CPNPP with Westinghouse-supplied AR relays with latch assembly used in protection system equipment. This particular modification has been completed prior to shipments of the equipment to the site. Confirmation and documentation of the modification is in accordance with established Westinghouse PWR QA procedures. Changes to the equipment resolve a tolerance problem discovered and reported to the NRC by Westinghouse. The modified relay was requalified for the nuclear application.

In addition, the NRC noted that at some operating plants BFD-31 relays were not qualified for the equalizing voltage. The I & C protection systems for CPNPP do not employ BFD relays. Refer to Section 7.2.2.2.3 for further discussion of solid state logic testing.

7.2.1.1.8 Isolation Amplifiers

In certain applications, Westinghouse considers it advantageous to employ control signals derived from individual protection channels through isolation amplifiers contained in the protection channel, as permitted by IEEE Standard 279-1971.

In all of these cases, analog signals derived from protection channels for nonprotective functions are obtained through isolation amplifiers located in the analog protection racks. By definition, nonprotective functions include those signals used for control, remote process indication, and computer monitoring.

7.2.1.1.9 Energy Supply and Environmental Variations

The energy supply for the RTS, including the voltage and frequency variations, is described in Section 7.6 and Chapter 8. The environmental variations, throughout which the system will perform, is given in Sections 3.11N and 8.3.

The reactor protection system is designed in a manner to prevent the load dispatch system from interfering with the safety actions. This is accomplished by means of not interconnecting the Luminant Power load dispatch system to the CPNPP reactor protection system.

Also the turbine loading is dependent on the reactor operator action on the turbine control system.

7.2.1.1.10 Setpoints

The setpoints that require trip action are given in the Technical Specifications. A detailed discussion on setpoints is found in Section 7.1.2.1.9.

7.2.1.1.11 Seismic Design

The seismic design considerations for the RTS are given in Section 3.10N. This design meets the requirements of Criterion 2 of the 1971 General Design Criteria (GDC).

7.2.1.2 Design Basis Information

The information given below presents the design basis information requested by Section 3 of IEEE Standard 279-1971. Functional logic diagrams are presented in Figure 7.2-1.

7.2.1.2.1 Generating Station Conditions

The following are the generating station conditions requiring reactor trip.

1. DNBR approaching the safety analysis limit applicable to the specific DNB correlation being used.

2. Power density (kilowatts per foot) approaching rated value for Condition II events (see Section 4.2 for fuel design limits).

3. Reactor Coolant System overpressure creating stresses approaching the limits specified in Section 5.2.

7.2.1.2.2 Generating Station Variables

The following are the variables required to be monitored in order to provide reactor trips (see Table 7.2-1). Except for the Reactor Coolant Pump Underfrequency/Undervoltage sensors, refer to Figure 7.1-3 for the location of the sensors which provide these trip inputs. Refer to explanatory note 7 on Sheet 1 of Figure 7.1-3 for the location of the and Reactor Coolant Pump Underfrequency/Undervoltage sensors.

1. Neutron flux.

2. Reactor coolant temperature.

3. Reactor Coolant System pressure (pressurizer pressure).

4. Pressurizer water level.

5. Reactor coolant flow.

6. Reactor coolant pump operational status (voltage and frequency).

7. Steam generator water level.

8. Turbine-generator operational status (trip fluid pressure and stop valve position).

9. N-16 gamma flux.

7.2.1.2.3 Spatially Dependent Variables

The following variable is spatially dependent:

1. The T_{avg} input for which the measurement of N-16 is used is the only indirect measurement which has spatial dependence because the N-16 power measurement has radial and azimuthal spatial dependence. As discussed in Section 7.2.1.1.4.2. the N-16 gamma radiation is detected by ion chambers located on the hot leg piping of each coolant loop. Detectors are mounted on the opposite sides of the hot leg so that asymmetries due to geometrical effects can be averaged out for the measured N-16. The signals from the two detectors are summed in the N-16 power module, to form one loop's uncompensated N-16 signal.

7.2.1.2.4 Limits, Margins and Setpoints

The parameter values that will require reactor trip are given in Section 15.0 and the Technical Specifications. Chapter 15 proves that the setpoints used in the Technical Specifications are conservative.

The setpoints for the various functions in the RTS have been analytically determined such that the operational limits so prescribed will prevent fuel rod clad damage and loss of integrity of the Reactor Coolant System as a result of any American Nuclear Society (ANS) Condition II event (anticipated malfunction). As such, during any ANS Condition II event, the RTS limits the following parameters to:

1. Minimum DNBR ≥ applicable limit value.

2. Maximum system pressure = 2750 pounds per square inch absolute (psia).

3. Fuel rod maximum linear power for determination of protection setpoints = 18.0 kilowatts per foot (kw/ft)

The accident analyses described in Chapter 15 demonstrate that the functional requirements as specified for the RTS are adequate to meet the above considerations, even assuming, for conservatism, adverse combinations of instrument errors. A discussion of the safety limits associated with the reactor core and Reactor Coolant System, plus the limiting safety system setpoints, are presented in the Technical Specifications.

7.2.1.2.5 Abnormal Events

The malfunctions, accidents or other unusual events which could physically damage RTS components or could cause environmental changes and the protection criteria followed are:

1. Earthquakes (see Sections 3.7N and 3.7B).

2. Fire (see Section 9.5.1).

3. Deleted.

4. Missiles (see Section 3.5).

5. Flood (see Section 3.4).

6. Wind and tornadoes (see Section 3.3).

7. Loss of coolant accidents (see Section 6.2)

8. Steam line breaks (see Section 6.2)

9. Loss of ventilation (see Section 9.4)

The RTS fulfills the requirements of IEEE Standard 279-1971 to provide automatic protection and to provide initiating signals to mitigate the consequences of faulted conditions.

7.2.1.2.6 Minimum Performance Requirements

1. RTS response times

   RTS response time is defined in Section 7.1. The maximum allowable time delays tabulated in Table 7.2-3 represent functional design values as opposed to acceptance criteria for response time testing. The Technical Specification response time requirements ensure that reactor protection system functional operability is maintained relative to these reference values. Refer to Section 7.1.2.11 for a discussion of periodic response time verification capabilities.

2. Reactor trip accuracies

   Accuracy is defined in Section 7.1. Reactor trip accuracies are tabulated in Table 7.2-3. An additional discussion on accuracy is found in Section 7.1.2.1.9.

3. Protection System ranges

   The Protection System ranges are tabulated in Table 7.2-3. Range selection for the instrumentation covers the expected range of the process variable being monitored during power operation. Limiting setpoints are at least 5 percent from the end of the instrument span.

7.2.1.3 Final Systems Drawings

Functional block diagrams, electrical elementaries and other drawings required to assure electrical separation and perform a safety review are provided in the Safety-Related Drawing Package (see Section 1.7).

7.2.2 ANALYSES

7.2.2.1 Failure Mode and Effects Analyses

An analysis of the RTS has been performed. Results of this study and a fault tree analysis are presented in Reference [4].

7.2.2.2 Evaluation of Design Limits

While most setpoints used in the Reactor Protection System are fixed, there are variable setpoints, most notably the Overtemperature N-16 setpoint. All setpoints in the RTS have been selected on the basis of engineering design or safety studies. The capability of the RTS to prevent loss of integrity of the fuel cladding and/or Reactor Coolant System pressure boundary during Condition II and III transients is demonstrated in Chapter 15. These accident analyses are carried out using those setpoints determined from results of the engineering design studies. Setpoint limits are presented in the Technical Specifications. A discussion of the intent for each of the various reactor trips and the accident analyses (where appropriate) which utilizes this trip is presented below. It should be noted that the selected trip setpoints all provide for margin before protection action is actually required to allow for uncertainties and instrument errors. The design meets the requirements of Criteria 10 and 20 of the 1971 GDC.

7.2.2.2.1 Trip Setpoint Discussion

The DNBR existing at any point in the core for a given core design can be determined as a function of the core inlet temperature, power output, operating pressure and flow. Consequently, core safety limits in terms of a DNBR equal to a unit specific or applicable DNBR limit value for the hot channel can be developed as a function of core power, T_{cold} and pressure for a specified flow as illustrated by the solid lines in Figure 15.0-1. Also shown as a dashed line in Figure 15.0-1 is a line equivalent to 118 percent of power representing the overpower (kW/ft) limit on the fuel. The dashed lines indicate the maximum permissible setpoint (N-16) as a function of T_{cold} and pressure for the overtemperature and overpower reactor trip. Actual setpoint constants in the equation representing the dashed lines are as given in the Technical Specifications. These values are conservative to allow for instrument errors. The design meets the requirements of Criteria 10, 15, 20 and 29 of the 1971 GDC.

DNBR is not a directly measurable quantity; however, the process variables that determine DNBR are sensed and evaluated. Small isolated changes in various process variables may not individually result in violation of a core safety limit, whereas the combined variations, over sufficient time, may cause the overpower or overtemperature safety limit to be exceeded. The design concept of the RTS takes cognizance of this situation by providing reactor trips associated with individual process variables in addition to the overpower/overtemperature safety limit trips. Process variable trips prevent reactor operation whenever a change in the monitored value is such that a core or system safety limit is in danger of being exceeded should operation continue. Basically, the high pressure, low pressure and Overpower/Overtemperature N-16 trips provide sufficient protection for slow transients as opposed to such trips as low flow or high flux which will trip the reactor for rapid changes in flow or flux, respectively, that would result in fuel damage before actuation of the slower responding N-16 trips could be effected.

Therefore, the RTS has been designed to provide protection for fuel cladding and Reactor Coolant System pressure boundary integrity where: 1) a rapid change in a single variable or factor could potentially result in exceeding a core or a system safety limit, and 2) a slow change in one or more variables will have an integrated effect which will cause safety limits to be exceeded. Overall, the RTS offers diverse and comprehensive protection against fuel cladding failure and/or loss of Reactor Coolant System integrity for Condition II and III accidents. This is demonstrated by Table 7.2-4 which lists the various trips of the RTS, the corresponding Technical Specification on safety limits and safety system settings and the appropriate accident discussed in the safety analyses in which the trip could be utilized.

It should be noted that the RTS automatically provides core protection during nonstandard operating configurations, i.e., operation with a loop out of service. Although operating with a loop out of service over an extended time is considered to be an unlikely event, no Protection System setpoints need to be reset. This is because the nominal value of the power (P-8) interlock setpoint restricts the power such that a DNBR less than the limit value will not be realized during any Condition II transients occurring during this mode of operation. This restricted power is considerably below the boundary of permissible values as defined by the core safety limits for operation with a loop out of service. Thus the P-8 interlock acts essentially as a high nuclear power reactor trip when operating with one loop not in service. The Technical Specifications do not allow continued operation in Modes 1 or 2 with less than four reactor coolant loops in service.

The design meets the requirements of Criterion 21 of the 1971 GDC.

Preoperational testing is performed on RTS components and systems to determine equipment readiness for startup. This testing serves as a further evaluation of the system design.

Analyses of the results of Condition I, II, III and IV events including considerations of instrumentation installed to mitigate their consequences are presented in Chapter 15. The instrumentation installed to mitigate the consequences of load rejection and turbine trip is given in Section 7.4.

7.2.2.2.2 Reactor Coolant Flow Measurement

The elbow taps used on each loop in the primary coolant system are instrument devices that indicate the status of the reactor coolant flow. The basic function of this device is to provide information as to whether or not a reduction in flow has occurred. The correlation between flow and elbow tap signal is given by the following equations:

$$P = k(w)^2 \text{ and } P_o = k(w_o)^2$$

where P_o is the pressure differential at the reference flow w_o, P is the pressure differential at the corresponding flow w, and k is a constant of proportionality. The full flow reference point is established during plant startup following each refueling outage. The low flow trip point is then established by extrapolating along the correlation curve. The expected absolute accuracy of the channel is within ± 10 percent of full flow and field results have shown the repeatability of the trip point to be within ± 1 percent.

7.2.2.2.3 Evaluation of Compliance to Applicable Codes and Standards

The RTS meets the criteria of the GDC as indicated. The RTS meets the requirements of Section 4 of IEEE Standard 279-1971, as indicated below.

1. General functional requirement

   The Protection System automatically initiates appropriate protective action whenever a condition monitored by the system reaches a preset level. Functional performance requirements are given in Section 7.2.1.1.1. Section 7.2.1.2.4 presents a discussion of limits, margins and levels; Section 7.2.1.2.5 discusses unusual (abnormal) events; and Section 7.2.1.2.6 presents minimum performance requirements.

2. Single failure criterion

   The Protection System is designed to provide two, three, or four instrumentation channels for each protective function and two logic train circuits. These redundant channels and trains are electrically isolated and physically separated. Thus, any single failure within a channel or train will not prevent protective action at the system level when required. Loss of input power, the most likely mode of failure, to a channel or logic train will result in a signal calling for a trip. This design meets the requirements of Criterion 23 of the 1971 GDC.

To prevent the occurrence of common mode failures, such additional measures as functional diversity, physical separation, and testing as well as administrative control during design, production, installation and operation are employed, as discussed in Reference [4]. The design meets the requirements of Criteria 21 and 22 of the 1971 GDC.

3. Quality of components and modules

For a discussion on the quality of the components and modules used in the RTS, see References [1], [2], [3], and [5]. The quality assurance applied conforms to Criterion 1 of the 1971 GDC.

4. Equipment qualification

For a discussion of the type tests made to verify the performance requirements, refer to Section 3.11N and 3.11B. The test results demonstrate that the design meets the requirements of Criterion 4 of the 1971 GDC.

5. Channel integrity

Protection System channels required to operate in accident conditions maintain necessary functional capability under extremes of conditions relating to environment, energy supply, malfunctions, and accidents. The energy supply for the RTS is described in Sections 7.6 and 8.3.1.1.13. The environmental variations throughout which the system will perform is given in Section 3.11N.

6. Independence

Channel independence is carried throughout the system, extending from the sensor through to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs and Containment penetrations for each redundant channel. Redundant analog equipment is separated by locating modules in different protection cabinets. Each redundant protection channel set is energized from a separate AC power feed. This design meets the requirements of Criterion 21 of the 1971 GDC.

Two reactor trip breakers are actuated by two separate logic matrices which interrupt power to the control rod drive mechanisms. The breaker main contacts are connected in series with the power supply so that opening either breaker interrupts power to all full length control rod drive mechanisms, permitting the rods to free fall into the core. Refer to Figure 7.1-1.

The design philosophy is to make maximum use of a wide variety of measurements. The Protection System continuously monitors numerous diverse system variables. Generally, two or more diverse protection functions would terminate an accident before intolerable consequences could occur. This design meets the requirements of Criterion 22 of the 1971 GDC.

7. Control and Protection System interaction

The Protection System is designed to be independent of the Control System. In certain applications the control signals and other nonprotective functions are derived from individual protective channels through isolation amplifiers. The isolation amplifiers are classified as part of the Protection System and are located in the analog protective racks. Nonprotective functions include those signals used for control, remote process indication, and computer monitoring. The isolation amplifiers are designed such that a short circuit, open circuit, or the application of credible fault voltages from within the cabinets on the isolated output portion of the circuit (i.e., the nonprotective side of the circuit) will not affect the input (protective) side of the circuit. The signals obtained through the isolation amplifiers are never returned to the protective racks. This design meets the requirements of Criterion 24 of the 1971 GDC and Section 4.7 of IEEE Standard 279-1971.

The results of applying various malfunction conditions on the output portion of the isolation amplifiers show that no significant disturbance to the isolation amplifier input signal occurred.

8. Derivation of system inputs

To the extent feasible and practical, Protection System inputs are derived from signals which are direct measures of the desired variables. Variables monitored for the various reactor trips are listed in Section 7.2.1.2.2.

9. Capability for sensor checks

The operational availability of each system input sensor during reactor operation is accomplished by cross checking between channels that bear a known relationship to each other and that have readouts available. Channel checks are discussed in the Technical Specifications Bases.

10. Capability for testing

The RTS is capable of being tested during power operation. Where only parts of the system are tested at any one time, the testing sequence provides the necessary overlap between the parts to assure complete system operation. The testing capabilities are in conformance with Regulatory Guide 1.22 as discussed in Section 7.1.2.5.

The Protection System is designed to permit periodic testing of the analog channel portion of the RTS during reactor power operation without initiating a protective action unless a trip condition actually exists. This is because of the ability to test the analog system in bypass and the coincidence logic required for reactor trip. These tests may be performed at any plant power from cold shutdown to full power. Before starting any of these tests with the plant at power, all redundant reactor trip channels associated with the function to be tested must be in the normal (untripped) mode in order to avoid spurious trips. Setpoints are referenced in the CPNPP technical specifications and/or the Instrument and Control Equipment List.

Analog Channel Tests

Analog channel testing is performed at the analog instrumentation rack set by individually introducing dummy input signals into the instrumentation channels and observing the tripping of the appropriate output bistables. Process analog output to the logic circuitry may be bypassed during individual channel test by a test switch which, when thrown, maintains the associated logic input. The bypass capability is designed so that credible failures (e.g., relays) will not result in a function being automatically placed in a bypassed condition. Both a local status light and a main control room annunciator are provided to indicate a bypassed condition. Interruption of the bistable output to the logic circuitry for any cause (test, maintenance purposes, or removed from service) will cause that portion of the logic to be actuated (partial trip) accompanied by a partial trip alarm and channel status light actuation in the Control Room. Each channel contains those switches, test points, etc., necessary to test the channel. Refer to References [1] and [2] for additional background information.

The following periodic tests of the analog channels of the protection circuits are performed:

a. T_{avg} and N-16 protection channel testing.

b. Pressurizer pressure protection channel testing.

c. Pressurizer water level protection channel testing.

d. Steam generator water level protection channel testing.

e. Reactor coolant low flow protection channels.

f. Impulse chamber pressure channel testing.

g. Steam pressure protection channels.

h. Containment pressure.

Nuclear Instrumentation Channel Tests

The power range channels of the Nuclear Instrumentation System may be tested by superimposing a test signal on the actual detector signal being received by the channel at the time of testing. These channels which produce a rod stop, permissive, or a reactor trip on one-out-of-four, two-out-of-four, or three-out-of-four logic are provided with a bypass function to prevent initiation of an undesired action from that system function during the period that one channel is in test. To permit testing in the bypass condition, a test panel is provided on each of the four NIS protection sets. Use of administrative controls will ensure that not more than one channel will be bypassed at a time. The bypass capability is designed so that credible failures (e.g., relays) will not result in a function being automatically placed in a bypassed condition. Annunciators in the main control room and bypass status lights on the bypass test panels are provided to indicate the bypassed condition.

To test a power range channel, a “TEST-OPERATE” switch is provided to require deliberate operator action and operation of which will initiate the “CHANNEL TEST” annunciator in the Control Room. Bistable operation may be tested by increasing the test signal to its trip setpoint and verifying bistable relay operation by control board annunciator and trip status lights.

If a channel is tested by superimposing a test signal on the actual detector signal, it should be noted that a valid trip signal would cause the channel under test to trip at a lower actual reactor power level. A reactor trip would occur when a second bistable trips.

A Nuclear Instrumentation System channel which can cause a reactor trip through one out of two protection logic (source or intermediate range) is provided with a bypass function which prevents the initiation of a reactor trip from that particular channel during the short period that it is undergoing test. These bypasses are annunciated in the Control Room.

The following represents the technical concept (not a circuit analysis) for testing flux rate trips while the plant is at power.

a. During normal operation at steady power level, the percent full power meter reading at the Nuclear Instrumentation System cabinets is recorded. The reading is the result of summing the outputs from detectors A and B in the circuits (A + B = % power).

b. A test signal, B' is added to the detector B signal such that:

   A + B + B' = X%

   where: X is a power level greater than 100% which is specified by station procedure. Additionally, a test signal A' is added to the detector A signal such that:

   A + A' + B + B' = Y% and

   Y - X = A' = the positive/negative rate trip percentage.

c. The test signal A' is added/removed by operation of the Operation Selector switch to effect a rapid positive/negative change in power level equal to A'. This is seen by the rate sensing circuits. The positive rate trip is confirmed in accordance with Technical Specifications.

The following periodic tests of the Nuclear Instrumentation System are performed (listed also are the modes during which that testing is permitted):

a. Source Range:	Analog Channel Operational Test - Any Mode[(a)] Channel Calibration - Any Mode[(a)] Analog Channel Calibration, High Flux at Shutdown - Any Mode[(a)] Signal Conditioning (Channel Calibration) - Any Mode[(a)]
b. Intermediate Range:	Analog Channel Operational Test - Mode 1 > 10% or, in modes 3, 4, 5, or 6. Neutron detector plateau - > 10% power
c. Power Range:	Analog Channel Operational Test - Any Mode Channel Calibration - Any Mode Detector Plateau - > 10% power

a) Not permitted with core alterations in progress

Any deviations noted during the performance of these tests are investigated and corrected in accordance with the established calibration and trouble shooting procedures provided in the plant technical manual for the Nuclear Instrumentation System. Control and protection trip settings are indicated in the CPNPP Technical Specifications and/or the Instrument and Controls Equipment List.

For additional background information on the Nuclear Instrumentation System, refer to Reference [2].

Undervoltage and Underfrequency Channel Tests

The test procedure for the undervoltage and underfrequency channels is as follows. Individual undervoltage channels are tested by a test switch which, when operated, de-energizes the undervoltage relay, operates the associated time delay relay, and in turn will actuate the corresponding portion of the logic (partial trip) accompanied by a partial trip alarm and channel status light actuation in the Control Room. Individual underfrequency channels are tested in the same way, except that the activation of an underfrequency relay requires that the test switch, when operated, connects the underfrequency relay to an external variable frequency test source.

Undervoltage, underfrequency and time delay relays are mounted in drawout cases to permit periodic testing of setpoint and accuracy of these relays.

Solid State Logic Testing

The reactor logic trains of the RTS are designed to be capable of complete testing at power. After the individual channel testing is complete, the logic matrices are tested from

the train A and train B logic rack test panels. This step provides overlap between the channel and logic portions of the test program. During this test, all of the logic inputs are actuated automatically in all combinations of trip and non-trip logic. Trip logic is not maintained sufficiently long enough to permit opening of the reactor trip breakers. The reactor trip undervoltage coils are “pulsed” in order to check continuity. During logic testing of one train, the other train can initiate any required protective functions. Annunciation is provided in the Control Room to indicate when a train is in test (train output bypassed) and when a reactor trip breaker is bypassed. Logic testing can be performed in less than 30 minutes.

A direct reactor trip resulting from undervoltage or underfrequency on the reactor coolant pump buses is provided as discussed in Section 7.2.1 and shown on Figure 7.2-1. The logic for these trips is capable of being tested during power operation. When parts of the trip are being tested, the sequence is such that an overlap is provided between parts so that a complete logic test is provided. Undervoltage and underfrequency sensors are tested as described above. Thus complete testing of the equipment discussed above is possible.

This design complies with the testing requirements of IEEE Standard 279-1971 and IEEE Standard 338-1971 discussed in Section 7.1.2.11.

The permissive and block interlocks associated with the RTS and Engineered Safety Features Actuation System are given on Tables 7.2-2 and 7.3-3 and designated protection or “P” interlocks. As a part of the Protection System, these interlocks are designed to meet the testing requirements of IEEE Standard 279-1971 and IEEE Standard 338-1971.

Testing of all Protection System interlocks is provided by the logic testing and semiautomatic testing capabilities of the Solid State Protection System. In the Solid State Protection System the undervoltage coils (reactor trip) and master relays (engineered safeguards actuation) are pulsed for all combinations of trip or actuation logic with and without the interlock signals. For example, reactor trip on low flow (two out of four loops showing two out of three low flow) is tested to verify operability of the trip above P-7 and non-trip below P-7 (see Figure 7.2-1, Sheet 5). Interlock testing may be performed at power.

Testing of the logic trains of the RTS includes a check of the input relays and a logic matrix check.

a. Check of input relays

Each Process Instrumentation System and Nuclear Instrumentation System channel bistable is placed in a trip mode causing one input relay in train A and one in train B to de-energize. A contact of each relay is connected to a universal logic printed circuit card. This card performs both the reactor trip and monitoring functions. Each reactor trip input relay contact causes a status lamp and an annunciator on the control board to operate. Either the train A or train B input relay operation will light the status lamp and annunciator.

Each train contains a multiplexing test switch. At the start of input relay testing, this switch (in either train) is placed in the A + B position. The A + B position alternately

allows information to be transmitted from the two trains to the control board. A steady status lamp and annunciator indicates that input relays in both trains have been de-energized. A flashing lamp means that the input relays in the two trains did not both de-energize. Contact inputs to the logic protection system such as reactor coolant pump bus underfrequency relays operate input relays which are tested by operating the remote contacts as described above and using the same type of indications as those provided for bistable input relays.

Actuation of the input relays provides the overlap between the testing of the logic protection system and the testing of those systems supplying the inputs to the logic protection system. Test indications are status lamps and annunciators on the control board. Inputs to the logic protection system are checked one channel at a time, leaving the other channels in service. For example, a function that trips the reactor when two out of four channels trip becomes a one out of three trip when one channel is placed in the trip mode. Both trains of the logic protection system remain in service during this portion of the test.

b. Check of logic matrices

Logic matrices are checked one train at a time. Input relays are not operated during this portion of the test. Reactor trips from the train being tested are inhibited with the use of the input error inhibit switch on the semiautomatic test panel in the train. At the completion of the logic matrix tests, one bistable in each protection set of process instrumentation or nuclear instrumentation is tripped to check closure of the input error inhibit switch contacts.

The logic test scheme uses pulse techniques to check the coincidence logic. All possible trip and non-trip combinations are checked. Pulses from the tester are applied to the inputs of the universal logic card at the same terminals that connect to the input relay contacts. Thus there is an overlap between the input relay check and the logic matrix check. Pulses are fed back from the reactor trip breaker undervoltage coil to the tester. The pulses are of such short duration that the reactor trip breaker undervoltage coil armature cannot respond mechanically.

Test indications that are provided are an annunciator in the Control Room indicating that reactor trips from the train have been blocked and that the train is being tested, and green and red lamps on the semiautomatic tester to indicate a good or bad logic matrix test. Protection capability provided during this portion of the test is from the train not being tested.

The testing capability meets the requirements of Criterion 21 of the 1971 GDC.

Testing of Reactor Trip Breakers

Normally, reactor trip breakers 52/RTA and 52/RTB are in service, and bypass breakers 52/BYA and 52/BYB are withdrawn (out of service). In testing the protection logic, pulse techniques are used to avoid tripping the reactor trip breakers. The following procedure describes the method used for testing the trip breakers:

a. With bypass breaker 52/BYA in the test position, manually close and trip it to verify its operation.

b. Rack in and close 52/BYA. Manually trip 52/RTA through a protection system logic matrix or by a Reactor Trip Test pushbutton via a keylocked test selector switch.

c. Reset 52/RTA.

d. Trip and rack out 52/BYA.

e. Repeat above steps to test trip breaker 52/RTB using bypass breaker 52/BYB.

Auxiliary contacts of the bypass breakers are connected into the alarm system of their respective trains such that if either train is placed in test while the bypass breaker of the other train is closed, both reactor trip breakers and both bypass breakers will automatically trip.

Auxiliary contacts of the bypass breakers are also connected in such a way that if an attempt is made to close the bypass breaker in one train while the bypass breaker of the other train is already closed, both bypass breakers will automatically trip.

The two bypass breakers train A and train B alarm systems operate separate annunciators in the Control Room. Bypassing of a protection train with either the bypass breaker or with the test switches will result in audible and visual indications.

The complete RTS is normally required to be in service. However, to permit on-line testing of the various protection channels or to permit continued operation in the event of a subsystem instrumentation channel failure, Technical Specification 3.3.1, defining the required number of operable channels, has been formulated. This Technical Specification also defines the required restriction to operation in the event that the channel operability requirements cannot be met.

11. Channel bypass or removal from operation

The Protection System is designed to permit periodic testing of the analog channel portion of the RTS during reactor power operation without initiating a protective action unless a trip condition actually exists. This is because of the ability to test the analog system in bypass and the coincidence logic required for reactor trip. Additional information is given in Section 7.2.2.2.3, item 10.

12. Operating bypasses

Where operating requirements necessitate automatic or manual bypass of a protective function, the design is such that the bypass is removed automatically whenever permissive conditions are not met. Devices used to achieve automatic removal of the bypass of a protective function are considered part of the Protective System and are designed in accordance with the criteria of this section. Indication is provided in the control room if some part of the system has been administratively bypassed or taken out of service.

13. Indication of bypasses

Channels associated with protection logic are provided with bypass functions which are annunciated in the control room, with the exception of undervoltage and underfrequency protection circuits.

Underfrequency and undervoltage relay testing is under administrative controls.

Each bypass breaker is separately annunciated in the Control Room by visible and audible alarms.

See discussion under item 10 above.

14. Access to means for bypassing

The design provides for administrative control of access to the means for manually bypassing channels or protective functions.

15. Multiple setpoints

For monitoring neutron flux, multiple setpoints are used. When a more restrictive trip setting becomes necessary to provide adequate protection for a particular mode of operation or set of operating conditions, the Protective System circuits are designed to provide positive means or administrative control to assure that the more restrictive trip setpoint is used. The devices used to prevent improper use of less restrictive trip settings are considered part of the Protective System and are designed in accordance with the criteria of this section.

16. Completion of protective action

The Protection System is so designed that, once initiated, a protective action goes to completion. Return to normal operation requires action by the operator.

17. Manual initiation

Switches are provided on the control board for manual initiation of protective action. Failure in the automatic system does not prevent the manual actuation of the protective functions. Manual actuation relies on the operation of a minimum of equipment.

18. Access

The design provides for administrative control of access to all setpoint adjustments, module calibration adjustments, and test points.

19. Identification of protective actions

Protective channel identification is discussed in Section 7.1.2.3. Indication is discussed in Item 20 below.

20. Information read out

The Protective System provides the operator with complete information pertinent to system status and safety. All transmitted signals (flow, pressure, temperature, etc.) which can cause a reactor trip will be either indicated or recorded for every channel, including all neutron flux power range currents (sum of two top detectors, sum of two bottom detectors, and difference of the two summed detector signals).

Any reactor trip will actuate an alarm and an annunciator. Such protective actions are indicated and identified down to the channel level.

Alarms and annunciators are also used to alert the operator of deviations from normal operating conditions so that he may take appropriate corrective action to avoid a reactor trip. Actuation of any rod stop or trip of any reactor trip channel will actuate an alarm.

21. System repair

The system is designed to facilitate the recognition, location, replacement, and repair of malfunctioning components or modules. Refer to the discussion in Item 10 above.

7.2.2.3 Specific Control and Protection Interactions

7.2.2.3.1 Neutron Flux

Four power range neutron flux channels are provided for overpower protection. An isolated auctioneered high signal is derived by auctioneering of the four channels for automatic rod control. If any channel fails in such a way as to produce a low output, that channel is incapable of proper overpower protection but will not cause control rod movement because of the auctioneer. Two out of four overpower trip logic will ensure an overpower trip if needed even with an independent failure in another channel.

In addition, channel deviation signals in the control system will give an alarm if any neutron flux channel deviates significantly from the average of the flux signals. Also, the control system will respond only to rapid changes in indicated neutron flux; slow changes or drifts are compensated by the temperature control signals. Finally, an over-power signal from any nuclear power range channel will block manual and automatic rod withdrawal. The setpoint for this rod stop is below the reactor trip setpoint.

7.2.2.3.2 Coolant Temperature

The accuracy of the in-line fast response thermowell-installed resistance temperature detector temperature measurements is demonstrated during plant startup tests by comparing temperature measurement from all resistance temperature detectors with one another as well as with the temperature measurements obtained from the wide range resistance temperature detector located in the hot leg and cold leg piping of each loop. The comparisons are done with the Reactor Coolant System in an isothermal condition. The linearity of the N-16 power measurements as a function of plant power is also checked during plant startup tests. The absolute value of N-16 versus plant power is not important, per se, as far as reactor protection is concerned. The RTS setpoints are based upon percentages of the indicated N-16 at nominal full power rather than on absolute values of ΔT. This is done to account for loop differences which

are inherent. Therefore the percent N-16 power scheme is relative, not absolute, and therefore provides better protective action without the expense of accuracy. For this reason, the linearity of the N-16 power signals as a function of power is of importance rather than the absolute values of N-16 power.

Reactor control is based upon signals derived from Protection System channels after isolation by isolation amplifiers such that no feedback effect can perturb the protection channels.

One of the inputs to the Rod Control System, which controls RCCA motion, is the average of the average temperatures (T-avg) for the four loops. Should one T-avg indication fail high, the average T-avg indication will be greater than the reference temperature, resulting in a demand for inward rod motion. With no operator intervention, the resulting mismatch between reactor power and turbine power will likely result in a reactor trip on low pressurizer pressure. If one T-avg indication was to fail low, the average T-avg indication would be less than the reference temperature, resulting in a demand for outward rod motion. The resulting T-err signal could be sufficient to drive rods out at maximum speed. Outward rod motion dies off as the following occurs:

1. The lead-lag characteristics of the T-avg circuit causes the circuit output to drop.

2. Auctioneered reactor power rises due to rod withdrawal.

Whether or not a high flux reactor trip occurs depends upon:

1. Initial bank D position.

2. The magnitude of the negative moderator temperature coefficient (MTC).

3. Magnitude of the doppler only power coefficient (DOPC).

As reactor power and temperature increase, the following can occur: C-2, C-3, and C-4 rod blocks: C-3 and C-4 turbine runbacks.

The scenario is bounded by the analyses of the control rod withdrawal events presented to FSAR Section 15.4. As needed operator intervention will consist of placing the rod control and pressurizer level control systems in manual until the failed channel is defeated. Once defeated, the averaging unit will use one average temperature input twice when developing the average T-avg.

In addition, channel deviation signals in the control system will give an alarm if any temperature channel deviates significantly from the average value. Automatic rod withdrawal blocks and turbine runback (power demand reduction) will also occur if any two out of four Overtemperature or Overpower N-16 channels indicate an adverse condition.

7.2.2.3.3 Pressurizer Pressure

The pressurizer pressure protection channel signals are used for high and low pressure protection and as inputs to the Overtemperature N-16 trip protection function. Isolated output signals from these channels are used for pressure control. These are used to control pressurizer

spray and heaters and power operated relief valves. Pressurizer pressure is sensed by fast response pressure transmitters.

A spurious high pressure signal from one channel can cause decreasing pressure by actuation of either spray or relief valves. Additional redundancy is provided in the low pressurizer pressure reactor trip and in the logic for safety injection to ensure low pressure protection.

Overpressure protection is based upon the positive surge of the reactor coolant produced as a result of turbine trip under full load, assuming the core continues to produce full power. The self-actuated safety valves are sized on the basis of steam flow from the pressurizer to accommodate this surge at a setpoint of 2500 psia and an accumulation of 3 percent. Note that no credit is taken for the relief capability provided by the power operated relief valves during this surge. However, the Power Operated Relief Valves (PORVs) provide operational control that limits the RCS pressure increase following transients. Therefore, the PORV actuation instrumentation is required to have a channel calibration every 18 months.

In addition, operation of any one of the power operated relief valves can maintain pressure below the high pressure trip point for most transients. The rate of pressure rise achievable with heaters is slow, and ample time and pressure alarms are available to alert the operator of the need for appropriate action.

Redundancy is not compromised by having a shared tap (see Section 7.2.1.1.2, item 2.a) since the logic for this trip is two out of three. If the shared tap is plugged, the affected channels will remain static. If the impulse line bursts, the indicated pressure will drop to zero. In either case the fault is easily detectable, and the protective function remains operable.

7.2.2.3.4 Pressurizer Water Level

The pressurizer has three differential pressure transmitters. Each transmitter employs an open column reference leg with a condensing pot to ensure that the reference leg maintains a constant level. The operation of the pressurizer water level measurement system is identical to that employed for measuring steam generator water level. See Section 7.2.2.3.5.

The pressurizer water level is used for the following safety functions: reactor trip on high water level and post-accident monitoring. Pressurizer water level provides no trip function following an accident which results in an adverse environment inside containment.

Isolated signals from the three pressurizer water level channels are used for pressurizer water level control. A failure in the level control system could fill or empty the pressurizer at a slow rate (on the order of half an hour or more). The high water level trip setpoint provides sufficient margin such that the undesirable condition of discharging liquid coolant through the safety valves is avoided. Even at full power conditions, which would produce the worst thermal expansion rates, a failure of the water level control would not lead to any liquid discharge through the safety valves. This is due to the automatic high pressurizer pressure reactor trip actuating at a pressure sufficiently below the safety valve setpoint.

A graph depicting level measurement error due to system pressure changes is shown in Figure 7.2-6. A plot similar to this is made available to the operators to ensure they are aware of potential level measurement error.

During required manual safety functions such as maintaining charging flow control within specified limits, the operator follows the applicable Emergency Operating Procedures (EOPs). This assures the operator of remaining within specified limits (accounting for adverse environmental errors). For example, the operator is instructed by the EOPs to re-establish operation of the pressurizer heaters only after verification of sufficient pressurizer heaters. Also, the operator is instructed to restore normal pressurizer level control after the containment temperatures are low enough to assure proper operation of the level control system. These actions ensure that, accounting for the post-accident level indication errors, the pressurizer heater will not be uncovered and the pressurizer will not become water solid.

7.2.2.3.5 Steam Generator Water Level

The steam generator narrow range and wide range water level detection system is located within containment and used to initiate safety actions. The steam generator narrow range water level detection system consists of four differential pressure measurement channels per steam generator. Each channel measures differential pressure between an upper and lower tap using an open column reference leg, a condensing pot to ensure that the reference leg maintains a constant level, and a differential pressure (level) transmitter.

The steam generator narrow range water level is used for the following safety functions:

1. Turbine trip and feedwater isolation on high-high steam generator water level,

2. Reactor trip on low-low steam generator water level,

3. Auxiliary feedwater initiation on low-low steam generator water level,

4. Post-accident monitoring.

Each steam generator has one wide range differential pressure transmitter. Each transmitter employs an open column reference leg with condensing pot to ensure that the reference leg maintains a constant level. When the steam generator level is high, the differential pressure between the vessel and the reference leg is smallest, as the steam generator level drops, the differential pressure increases. The steam generator wide range water level also has a post-accident monitoring function.

Transmitters are purchased such that the upper and lower range limits for the transmitters are greater than the upper and lower range values, i.e., the calibrated instrument range is not the design limit for the device.

The basic function of the reactor protection circuits associated with low-low steam generator water level is to preserve the steam generator heat sink for removal of long-term residual heat. Should a complete loss of feedwater occur, the reactor would be tripped on low-low steam generator water level. In addition redundant auxiliary feedwater pumps are provided to supply feedwater in order to maintain residual heat removal after trip. This reactor trip acts before the steam generators are dry. This reduces the required capacity, increases the time interval before auxiliary feedwater pumps are required, and minimizes the thermal transient on the Reactor Coolant System and steam generators. Therefore, a low-low steam generator water level reactor trip circuit is provided for each steam generator to ensure that sufficient initial thermal capacity is available in the steam generator at the start of the transient. Two-out-of-four low-low

steam generator water level trip logic ensures a reactor trip if needed even with an independent failure in another channel used for control and when degraded by an additional second postulated random failure.

A spurious low signal from the feedwater flow channel being used for control would cause an increase in feedwater flow. The mismatch between steam flow and feedwater flow produced by the spurious signal would actuate alarms to alert the operator of the situation in time for manual correction. If the condition continues, a two-out-of-three high-high steam generator water level signal in any loop, independent of the indicated feedwater flow, will cause feedwater isolation and trip the turbine. The high-high steam generator water level trip is an equipment protective trip preventing excessive moisture carryover which could damage the turbine blading.

The level control system for the steam generator uses one of the three steam generator level signals or a fourth signal, which is not used in the high-high steam generator logic. The fourth level signal shall always be used at CPNPP for steam generator level control, except when the signal is not operable or for testing. When this fourth level signal is used, the failure of a single level signal will not cause both a steam generator level logic to two-out-of-two. When the other level signal which is available for steam generator level control is selected and steam generator control is in automatic, the high-high steam generator isolation signal for the channel selected for steam generator level control will be placed in the tripped condition within the time limits specified in the Technical Spefications and shall remain in the tripped condition whenever steam generator level control is in automatic until the fourth level signal is operable and selected for control. This shall ensure that the requirements of IEEE-279 Section 4.7.3 and 10 CFR Part 50.55a(h) are adequately met.

In addition, the three element feedwater controller incorporates reset action on the level error signal, such that with expected controller settings a rapid increase or decrease in the flow signal would cause only a small change in level before the controller would compensate for the level error. A slow change in the feedwater signal would have no effect at all. A spurious low or high steam flow signal would have the same effect as high or low feedwater signal, discussed above.

A spurious high steam generator water level signal from the protection channel used for control will tend to close the feedwater valve. A spurious low steam generator water level signal will tend to open the feedwater valve. Before a reactor trip would occur, two-out-of-four channels in a loop would have to indicate a low-low water level. Any slow drift in the water level signal will permit the operator to respond to the level alarms and take corrective action.

High energy line breaks inside containment can result in the heating of level measurement reference legs. Increased reference leg water column temperature results in a decrease of the water column density with a consequent apparent increase in the indicated water level, i.e., apparent level exceeding actual level. The following formula can be used to calculate the magnitude of this bias:

$$E = \frac{H_L}{H} \frac{(P_L, cal - P_L)}{(P_f, cal - P_g, cal)}$$

Where:

E	=	Level error due to reference leg heatup, as a fraction of level span,
H	=	Level span = vertical distance between pressure taps - 233 in., nominal
H_L	=	Height of reference leg - 235 in., nominal
P_L, cal	=	Water density at containment temperature and system pressure for which the level indication system was calibrated. At CPNPP, the containment temperature is 120°F and the steam generator pressure is 1053 psia (70% power),
P_L	=	Water density in reference leg at the time of interest,
(P_f, cal-P_g, cal)	=	Difference between saturated water density and dry saturated steam density at the system pressure for which the level indication system was calibrated, 3.g., 1053 psia for CPNPP steam generators.

This procedure is based on the assumption that the tubing from the upper and lower taps, below the elevation of the lower tap, have the same temperatures at all times. Figure 7.2-4 shows the steam generator level bias as a function of reference leg temperature for CPNPP conditions.

In addition to the above reference leg density change under subcooled conditions, boiling could conceivably occur in the reference leg following depressurization of any steam generator with high containment temperature. This combination of conditions could only occur following a steam line or feedline rupture inside containment. If such boiling were to occur, it could cause a major bias in the indicated level for a short time period, in the extreme case indicating 100 percent level when the vessel is actually empty. However, containment analyses performed by Westinghouse indicate that such boiling would not occur.

A bias in indicated water level may also be introduced by changes in pressurizer or steam generator pressure, due to changes in the density of the saturated water and steam within those vessels. While prediction of the effects of rapid depressurization requires complex calculations for each specific case, the bias which would exist at low power under quiescent conditions can be calculated directly, using the following formula:

$$E = \frac{H_L}{H}\frac{(P_g - P_g, cal)}{(P_f, cal - P_g, cal)} + \frac{L}{H}\frac{(P_f - P_g)}{(P_f, cal - P_g, ccal)} - \frac{L}{H}$$

Where:

E	=	Level error due to density changes in both the vessel and the reference leg, as a fraction of level span,
L	=	True water level in the vessel, above the lower level tap,

P_f = Saturated water density at the pressure of interest,

P_g = Dry saturated steam density at the pressure of interest.

Note: Other symbols have the same meaning as in the previous formula.

For example, Figure 7.2-5 shows the true water level as a function of steam generator pressure and indicated level using the following CPNPP calibration conditions: containment temperature = 120°F, steam generator pressure = 1053 psia, and the reference leg at 120°F.

The only high energy line rupture within containment for which the steam generator water level provides the primary trip function is a secondary high energy line rupture from an initial high power condition. Based on its analyses and investigation, Westinghouse asserts that functions which have 95% probability setpoints (when including uncertainties using the approved Westinghouse setpoint methodology) within 5% of the top or bottom of the instrument range will not respond any differently than any other protection function. Because large steam generator pressure changes (Section 7.2.2.3.4) are not expected before trip, only the reference leg heatup effects need be considered, and not the effects of system pressure changes.

The basis for determination of the low-low setpoint is the loss of normal feedwater and feedline break events. The setpoints were determined by considering the level used in each of the analyses for each unit (0% of span in both cases). For each unit, the setpoint was determined by considering the following errors for feedline break:

1. Normal error, e.g., normal channel accuracy,

2. Post-accident effects on transmitter due to temperature,

3. Reference leg effects (post-accident heatup).

For loss of normal feedwater, only normal errors were considered since it does not result in an adverse environment.

At CPNPP the reference leg effects have been addressed in the determination of the low-low setpoints. Considering a steam line break containment temperature of 345°F, which bounds conditions for the feedline break, the error due to reference leg heatup will be approximately 14% span.

High-high steam generator water level trip is not required for accident situations that could cause significant errors in level indication. The setpoint of this trip will remain unchanged.

Steam generator wide range level does not provide any automatic trip functions.

A graph depicting the level measurement error due to steam generator reference leg heatup is shown in Figure 7.2-4. Error due to system pressure changes are shown in Figure 7.2-5. A plot similar to the latter figure is made available to the operators to ensure they are aware of the potential level measurement errors.

In addition, a remote possibility exists that the fluid in the open reference legs may flash to steam in the depressurized steam generators following a secondary high energy line rupture. To alert the operator to the possibility of erroneous indications, Westinghouse recommends that a Caution be inserted in all plant emergency instructions for indicated steam generator water level, which states that the operator should not rely upon steam generator water level indications in any depressurized steam generators following a high energy line rupture inside containment due to the possibility of reference leg boiling. The Westinghouse reference Emergency Operating Instructions take the post-accident indicated water level errors into account in the specification of the minimum levels required for safety injection terminations. Similar cautions are included in CPNPP emergency procedures.

7.2.2.4 Additional Postulated Accidents

Loss of plant instrument air or loss of component cooling water is discussed in Section 7.3.2. Load rejection and turbine trip are discussed in further detail in Section 7.7.

The control interlocks, called rod stops, that are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal are discussed in Section 7.7.1.4 and listed on Table 7.7-1. Excessively high power operation (which is prevented by blocking of automatic rod withdrawal), if allowed to continue, might lead to a safety limit (as given in the Technical Specifications) being reached. Before such a limit is reached, protection will be available from the RTS. At the power levels of the rod block setpoints, safety limits have not been reached; and therefore these rod withdrawal stops do not come under the scope of safety-related systems, and are considered as control systems.

7.2.3 TESTS AND INSPECTIONS

The RTS meets the testing requirements of IEEE Standard 338-1971, as discussed in Section 7.1.2.11. The test-ability of the system is discussed in Section 7.2.2.2.3. The initial test intervals are specified in the Technical Specifications. Written test procedures and documentation, conforming to the requirements of IEEE Standard 338-1971, will be available for audit by responsible personnel. Periodic testing complies with Regulatory Guide 1.22 as discussed in Sections 7.1.2.5 and 7.2.2.2.3.

REFERENCES

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2. Lipchak, J. B., “Nuclear Instrumentation System,” WCAP-8255, January 1974.

3. Katz, D. N., “Solid State Logic Protection System Description,” WCAP-7488-L (Proprietary), March 1971 and WCAP-7672 (Non- Proprietary), May 1971.

4. Gangloff, W. C. and Loftus, W. D., “An Evaluation of Solid State Logic Reactor Protection In Anticipated Transients,” WCAP-7706-L (Proprietary) and WCAP-7706 (Non-Proprietary), February 1971.

5. Graham, K. F., “N-16 Power Measuring System,” WCAP 9190 (Proprietary) and WCAP 9191 (Non-Proprietary), December, 1977.

6. Letter from R. Heineman (NRC) to C. Eicheldinger (Westinghouse) dated June 21, 1976 re: documentation of NRC acceptance of Solid State Protection System circuit modifications.

TABLE 7.2-1
LIST OF REACTOR TRIPS

(Sheet 1 of 2)

	Reactor Trip	Coincidence Logic	Interlocks	Comments
1.	Power range high neutron flux	2/4	Manual block of low setting permitted by P-10	High and low setting; manual block and automatic reset of low setting by P-10
2.	Intermediate range high neutron flux	1/2	Manual block permitted by P-10	Manual block and automatic reset
3.	Source range high neutron flux	1/2	Manual block permitted by P-6, interlocked with P-10	Manual block and automatic reset; automatic block above P-10
4.	Power range high positive neutron flux rate	2/4	No interlocks	-
5.	Not Used			
6.	Overtemperature N-16	2/4	No interlocks	-
7.	Overpower N-16	2/4	No interlocks	-
8.	Pressurizer low presure	2/4	Interlocked with P-7	Blocked below P-7
9.	Pressurizer high pressure	2/4	No interlocks	-
10.	Pressurizer high water level	2/3	Interlocked with P-7	Blocked below P-7

TABLE 7.2-1
LIST OF REACTOR TRIPS

(Sheet 2 of 2)

	Reactor Trip	Coincidence Logic	Interlocks	Comments
11.	Low reactor coolant flow	2/3 in any loop	Interlocked with P-7 and P-8	Low flow in one loop will cause a reactor trip when above P-8 and a low flow in two loops will cause a reactor trip when above P-7; blocked below P-7
12.	Reactor coolant pump undervoltage	2/4	Interlocked with P-7	Low voltage on all buses permitted below P-7.
13.	Reactor coolant pump underfrequency	2/4	Interlocked with P-7	Underfrequency on 2 motors will trip all reactor coolant pump breakers and cause reactor trip; reactor trip blocked below P-7
14.	Low-low steam generator water level	2/4 in any loop	No interlocks	-
15.	Safety injection signal	Coincident with actuation of safety injection	No interlocks	(See Section 7.3 for engineered safety features actuation conditions)
16.	Turbine (anticipatory) trip			
	a. Low trip fluid pressure	2/3	Interlocked with P-9	Blocked below P-9
	b. Turbine stop valve close	4/4	Interlocked with P-9	Blocked below P-9
17.	Manual	1/2	No interlocks	-

TABLE 7.2-2
PROTECTION SYSTEM INTERLOCKS

(Sheet 1 of 2)

Designation	Derivation	Function
	I Power Escalation Permissives	
P-6	Presence of P-6: 1/2 neutron flux (intermediate range) above setpoint	Allows manual block of source range reactor trip
	Absence of P-6: 2/2 neutron flux (intermediate range) below setpoint	Defeats the block of source range reactor trip
P-10	Presence of P-10: 2/4 neutron flux (power range) above setpoint	Allows manual block of power range (low setpoint) reactor trip
		Allows manual block of intermediate range reactor trip and intermediate range rod stops (C-1)
		Blocks source range reactor trip (back-up for P-6)
	Absence of P-10: 3/4 neutron flux (power range) below setpoint	Defeats the block of power range (low setpoint) reactor trip
		Defeats the block of intermediate range reactor trip and intermediate range rod stops (C-1)
		Input to P-7

TABLE 7.2-2
PROTECTION SYSTEM INTERLOCKS

(Sheet 2 of 2)

Designation	Derivation	Function
	II Blocks of Reactor Trips	
P-7	Absence of P-7: 3/4 neutron flux (power range) below set point (from P-10) and 2/2 turbine impulse chamber pressure below setpoint (from P-13)	Blocks reactor trip on: Low reactor coolant flow in more than one loop, undervoltage, underfrequency, pressurizer low pressure, and pressurizer high level
P-8	Absence of P-8: 3/4 neutron flux (power range) below setpoint	Blocks reactor trip on low reactor coolant flow in a single loop
P-9	Absence of P-9: 3/4 neutron flux (power range) below setpoint	Blocks reactor trip on turbine trip below approximately 50% power
P-13	2/2 turbine impulse chamber pressure below setpoint	Input to P-7

TABLE 7.2-3
REACTOR TRIP SYSTEM INSTRUMENTATION[a]

(Sheet 1 of 2)

	Reactor Trip Signal	Range	Trip Accuracy	Time Response(sec)
1.	Power range high neutron flux	1 to 120% full power	± 1% of full power	0.2
2.	Intermediate range high neutron flux	8 decades of neutron flux overlapping source range by 2 decades	± 5% of full scale ± 1% of full scale from 10% to 150% full power[b]	0.2
3.	Source range high neutron flux	6 decades of neutron flux (1 to 10^6 counts/ sec)	± 5% of full scale	0.2
4.	Power range high positive neutron flux rate	+15% of full power	± 5%[b]	0.2
5.	Not Used			
6.	Overtemperature N-16	N-16 0 to 150% power T_C 510 to 630°F P_{PRZR} 1700 to 2500 psig $F_{(\Delta\phi)}$ -50 to +50	± 4.0% span	N-16 1.0 T_C 6.0 P_{PRZR} 1.0
7.	Overpower N-16	N-16 0 to 150% power T_C 510 to 630°F	± 4.0% span	N-16 1.0 T_C 6.0
8.	Pressurizer low pressure	1700 to 2500 psig	± 18 psi (compensated signal)	0.6
9.	Pressurizer high pressure	1700 to 2500 psig	± 18 psi (non-compensated signal)	0.6

TABLE 7.2-3
REACTOR TRIP SYSTEM INSTRUMENTATION[a]

(Sheet 2 of 2)

	Reactor Trip Signal	Range	Trip Accuracy	Time Response(sec)
10.	Pressurizer high water level	Entire cylindrical portion of pressurizer (distance between taps)	2.25% of full range $\Delta\rho$ between taps at design temperature and pressure	1.2
11.	Low reactor coolant flow	$\Delta\rho$ equivalent of 0 to 120% of rated flow	2.75% $\Delta\rho$ span	0.3
12.	Reactor coolant pump undervoltage	0 to 100% rated voltage	±1%	0.7
13.	Reactor coolant pump underfrequency	50 to 65 Hz	±0.1 Hz	0.3
14.	Low-low steam generator water level	total distance between narrow range steam generator level taps	2.25% of $\Delta\rho$ span over pressure range of 700 to 1200 psig	1.2
15.	Turbine trip			0.3
	a. Stop valve position	N/A	±5% stroke (at closed position) of valve travel	
	b. Trip fluid pressure	0 to 200 psig	±10% of full scale	

a) Values represents functional requirements only

b) Reproducibility (see definitions in Section 7.1)

Accuracy of steam flow signal is ±3 percent of maximum calculated flow over the pressure range of 700 to 1200 psig.

TABLE 7.2-4
REACTOR TRIP CORRELATION

(Sheet 1 of 5)

	Trip[a]	Accident[b]	Technical Specification[c]
1.	Power range high neutron flux trip (low setpoint)	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical or Low Power Startup Condition (15.4.1)	3.3.1, Table 3.3.1-1 #2b
		Feedwater System Malfunctions that Result in a Decrease in Feedwater Temperature (15.1.1)	
		Spectrum of Rod Cluster Control Assembly Ejection Accidents (15.4.8)	
2.	Power range high neutron flux trip (high setpoint)	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical or Low Power Startup Condition (15.4.1)	3.3.1, Table 3.3.1-1 #2a
		Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.4.2)	
		Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature (15.4.4)	
		Feedwater System Malfunctions that Result in a Decrease in Feedwater Temperature (15.1.1)	
		Excessive Increase in Secondary Steam Flow (15.1.3)	
		Inadvertent Opening of a Steam Generator Relief or Safety Valve (15.1.4)	
		Spectrum of Steam System Piping Failures Inside and Outside of Containment in a PWR (15.1.5)	
		Spectrum of Rod Cluster Control Assembly Ejection Accidents (15.4.8)	
3.	Intermediate range high neutron flux trip (15.4.1)	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical or Low Power Startup Condition	See Note d[d], 3.3.1, Table 3.3.1-1 #4

TABLE 7.2-4
REACTOR TRIP CORRELATION

(Sheet 2 of 5)

	Trip[a]	Accident[b]	Technical Specification[c]
4.	Source range high neutron flux trip	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical or Low Power Startup Condition (15.4.1)	See Note d,[d] 3.3.1, Table 3.3.1-1 #5
5.	Power range high positive neutron flux rate trip	Uncontrolled RCCA Bank Withdrawal (15.4.2) Spectrum of Rod Cluster Control Assembly Ejection Accidents (15.4.8)	3.3.1, Table 3.3.1-1 #3
6.	Not Used		
7.	Overtemperature N-16 trip	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.4.2) Chemical and Volume Control System Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant (15.4.6) Loss of External Electrical Load (15.2.2) Turbine Trip (15.2.3) Feedwater System Malfunctions that Result in a Decrease in Feedwater Temperature (15.1.1) Excessive Increase in Secondary Steam Flow (15.1.3) Inadvertent Opening of a Pressurizer Safety or Relief Valve (15.6.1) Inadvertent Opening of a Steam Generator Relief or Safety Valve (15.1.4) Loss of Coolant Accidents Resulting from the Spectrum of Postulated Piping Breaks within the Reactor Coolant Pressure Boundary (15.6.5)	3.3.1, Table 3.3.1-1 #6 Note 1

TABLE 7.2-4
REACTOR TRIP CORRELATION

(Sheet 3 of 5)

	Trip[a]	Accident[b]	Technical Specification[c]
8.	Overpower N-16 Trip	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.4.2)	3.3.1, Table 3.3.1-1 #7
		Feedwater System Malfunctions that Result in a Decrease in Feedwater Temperature (15.1.1)	
		Excessive Increase in Secondary Steam Flow (15.1.3)	
		Inadvertent Opening of a Steam Generator Relief or Safety Valve (15.1.4)	
		Spectrum of Steam System Piping Failures Inside and Outside of Containment in a PWR (15.1.5)	
9.	Pressurizer low pressure trip	Inadvertent Opening of a Pressurizer Safety or Relief Valve (15.6.1)	3.3.1, Table 3.3.1-1 #8a
		Loss of Coolant Accidents Resulting from the Spectrum of Postulated Piping Breaks within the Reactor Coolant Pressure Boundary (15.6.5)	
		Steam Generator Tube Failure (15.6.3)	
		Rod Cluster Control Assembly Misalignment (15.4.3)	
10.	Pressurizer high pressure trip	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.4.2)	3.3.1, Table 3.3.1-1 #8b
		Loss of External Electrical Load (15.2.2)	
		Turbine Trip (15.2.3)	
11.	Pressurizer high water level trip	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.4.2)	3.3.1, Table 3.3.1-1 #9
		Loss of External Electrical Load (15.2.2)	
		Turbine Trip (15.2.3)	

TABLE 7.2-4
REACTOR TRIP CORRELATION

(Sheet 4 of 5)

	Trip[a]	Accident[b]	Technical Specification[c]
12.	Low reactor coolant flow	Partial Loss of Forced Reactor Coolant Flow (15.3.1)	3.3.1, Table 3.3.1-1 #10
		Loss of Non-Emergency AC Power To the Station Auxiliaries (15.2.6)	
		Complete Loss of Forced Reactor Coolant Flow (15.3.2)	
		Reactor Coolant Pump Shaft Seizure (Locked Rotor) (15.3.3)	
13.	Reactor coolant pump undervoltage trip	Complete Loss of Forced Reactor Coolant Flow (15.3.1)	3.3.1, Table 3.3.1-1 #12
14.	Reactor coolant pump underfrequency trip	Complete Loss of Forced Reactor Coolant Flow (15.3.1)	3.3.1, Table 3.3.1-1 #13
15.	Low-low steam generator water level trip	Loss of Normal Feedwater Flow (15.2.7)	3.3.1, Table 3.3.1-1 #14
		Loss of Non-Emergency AC Power to the Station Auxiliaries (15.2.6)	
		Feedwater System Pipe Break (15.2.8)	
16.	Reactor trip on turbine trip	Loss of External Electrical Load (15.2.2)	See Note d,[d] 3.3.1, Table 3.3.1-1 #16
		Turbine Trip (15.2.3)	
		Loss of Non-Emergency AC Power to the Station Auxiliaries (15.2.6)	See Note d[d]

TABLE 7.2-4
REACTOR TRIP CORRELATION

(Sheet 5 of 5)

	Trip[a]	Accident[b]	Technical Specification[c]
17.	Safety injection signal actuation trip	Inadvertent Opening of a Steam Generator Relief or Safety Valve (15.1.4)	See Note e[e] 3.3.1 Table 3.3.1-1 #17
		Steam System Piping Failure (15.1.5)	
18.	Manual trip	Available for all Accidents (Chapter 15)	See Note d 3.3.1 Table 3.3.1-1 #1

a) Trips are listed in order of discussion in Section 7.2.

b) References refer to accident analyses presented in Chapter 15.

c) References refer to Technical Specifications.

d) A Technical Specification is not required because this trip is not assumed to function in the accident.

e) Accident assumes that the reactor is tripped at end-of-life which is the worst initial condition for this case.

7.3 ENGINEERED SAFETY FEATURES SYSTEMS

In addition to the requirements for a reactor trip for anticipated abnormal transients, the facility is provided with adequate instrumentation and controls to sense accident situations and initiate the operation of necessary engineered safety features. The occurrence of a limiting fault, such as a loss of coolant accident or a steam line break, requires a reactor trip plus actuation of one or more of the engineered safety features in order to prevent or mitigate damage to the core and Reactor Coolant System components, and ensure containment integrity.

In order to accomplish these design objectives, timely initiating signals are to be supplied by the sensors, transmitters and logic components making up the various instrumentation channels of the Engineered Safety Features Actuation System (ESFAS). The details on the ESFAS signals and design are provided in Figure 7.3-4. The equipment arrangement is shown in Reference [2].

The protective functions pertaining to steamline break protection signal (an ESFAS Signal) are the Steamline isolation actuation and safety injection actuation signals generated when exceeding the setpoints of the following parameters.

1. Low pressurizer pressure - Initiates SI

2. High Containment Pressure - Hi-1 (initiates SI)

   Hi-2 initiates main steam line isolation - MSLI

3. Low Steamline Pressure - Initiates SI and MSLI

4. High Steam Pressure Rate - Initiates MSLI (only during normal cooldown and heat-up)

7.3.1 DESCRIPTION

The ESFAS uses selected plant parameters, determines whether or not predetermined safety limits are being exceeded and, if they are, combines the signals into logic matrices sensitive to combinations indicative of primary or secondary system boundary ruptures (Condition III or IV events). Once the required logic combination is completed, the system sends actuation signals to the appropriate engineered safety features components. The ESFAS meets the requirements of General Design Criteria (GDC) 13 and 20.

7.3.1.1 System Description

The ESFAS is a functionally defined system described in this section. The equipment which provides the actuation functions identified in Section 7.3.1.1.1 is listed below and discussed in this section. (For additional background information refer to References [1], [2], and [3].)

1. Process Instrumentation and Control System (Reference [1]).

2. Solid State Logic Protection System (Reference [2]).

3. Engineered Safety Features Test Cabinet (Reference [3]).

4. Manual Actuation Circuits.

The ESFAS consists of two discrete portions of circuitry: 1) an analog portion consisting of three to four redundant channels per parameter or variable to monitor various plant parameters such as the Reactor Coolant System and steam system pressures, temperatures and flows and containment pressures; and 2) a digital portion consisting of two redundant logic trains which receive inputs from the analog protection channels and perform the logic needed to actuate the engineered safety features. Each digital train is capable of actuating the engineered safety features equipment required. The intent is that any single failure within the ESFAS shall not prevent system action when required.

The redundant concept is applied to both the analog and logic portions of the system. Separation of redundant analog channels begins at the process sensors and is maintained in the field wiring, with containment vessel penetrations and analog protection racks terminating at the redundant safeguards logic racks. The design meets the requirements of Criteria 20, 21, 22, 23 and 24 of the 1971 GDC.

The variables are sensed by the analog circuitry as discussed in Reference [1] and in Section 7.2. The inputs from the analog channels 6, 7, and 8. Tables 7.3-1 and 7.3-2 give additional information pertaining to logic and function.

The interlocks associated with the ESFAS are outlined in Table 7.3-3. These interlocks satisfy the functional requirements discussed in Section 7.1.2.

Manual actuation from the control board of containment isolation Phase A is provided by operation of either one of the redundant momentary containment isolation Phase A controls. Each control consists of two back-up linked actuation switches. The separate trains are thereby linked by mechanical means in a fashion similar to that shown in Figure 7.2-3. Also on the control board is manual actuation of safety injection by one of the redundant controls and a manual activation of containment isolation Phase B by either of the two sets of controls.

Manual controls are also provided to switch from the injection to the recirculation phase after a loss of coolant accident.

7.3.1.1.1 Function Initiation

The specific functions which rely on the ESFAS for initiation are:

1. A reactor trip, provided one has not already been generated by the Reactor Trip System.

2. Cold leg injection isolation valves which are opened for injection of borated water by safety injection pumps into the cold legs of the Reactor Coolant System.

3. Charging pumps, safety injection pumps, residual heat removal pumps and associated valving which provide emergency makeup water to the cold legs of the Reactor Coolant System following a loss of coolant accident.

4. Containment spray pumps startup.

5. Those pumps which serve as part of the heat sink for containment cooling (e.g., service water and component cooling water pumps).

6. Motor driven auxiliary feedwater pumps, Turbine Driven Auxiliary Feedwater Pumps (open Steam Supply Valve)

7. Phase A containment isolation, whose function is to prevent fission product release. (Isolation of all lines not essential to reactor protection).

8. Steam line isolation to prevent the continuous, uncontrolled blowdown of more than one steam generator and thereby uncontrolled Reactor Coolant System cooldown.

9. Main feedwater line isolation as required to prevent or mitigate the effect of excessive cooldown.

10. Start the emergency diesels to assure back-up supply of power to emergency and supporting systems components.

11. Initiate the Control Room ventilation emergency recirculation to meet Control Room occupancy requirements following a loss of coolant accident.

12. Containment spray actuation which performs the following functions:

    a. Confirms spray pump startup (see item 4 above).

    b. Initiates containment spray by opening the spray valves to reduce containment pressure and temperature following a loss of coolant or steam line break accident inside of containment.

    c. Initiates Phase B containment isolation which isolates the containment following a loss of reactor coolant accident, or a steam or feedwater line break within containment to limit radioactive releases. (Phase B isolation together with Phase A isolation results in isolation of all but safety injection and containment spray lines penetrating the containment.)

7.3.1.1.2 Analog Circuitry

The process analog sensors and racks for the ESFAS are covered in Reference [1]. Discussed in this report are the parameters to be measured including pressures, flows, tank and vessel water levels, and temperatures as well as the measurement and signal transmission considerations. These latter considerations include the transmitters, orifices and flow elements, resistance temperature detectors, as well as automatic calculations, signal conditioning and location and mounting of the devices.

The sensors monitoring the primary system are located as shown on the piping flow diagrams in Chapter 5. The secondary system sensor locations are shown on the steam system flow diagrams given in Section 10.3.

Containment pressure is sensed by four physically separated differential pressure transmitters mounted by strong supports outside of the containment, (which are connected to containment atmosphere by a filled and sealed hydraulic transmission system). The distance from penetration to transmitter is kept to a minimum, and separation is maintained. This arrangement,

together with the pressure sensors external to the containment, forms a double barrier and conforms to GDC 56 and Regulatory Guide 1.11.

7.3.1.1.3 Digital Circuitry

The engineered safety features logic racks are discussed in detail in Reference [2]. The description includes the considerations and provisions for physical and electrical separation as well as details of the circuitry. Reference [2] also covers certain aspects of on-line test provisions, provisions for test points, considerations for the instrument power source, considerations for accomplishing physical separation. The outputs from the analog channels are combined into actuation logic as shown on Sheets 5, 6, 7, 8, and 14 of Figure 7.2-1.

To facilitate engineered safety features actuation testing, four cabinets (two per train) are provided which enable operation, to the maximum practical extent, of safety features loads on a group-by-group basis until actuation of all devices has been checked. Final actuation testing is discussed in detail in Section 7.3.2.

7.3.1.1.4 BOP Furnished Engineered Safety Features Systems

The BOP furnished engineered safety features systems (ESFS) are:

1. Containment Spray System
2. Containment Isolation System
3. Item Deleted.
4. Control Room Air-Conditioning System
5. Auxiliary Feedwater System
6. ESF Filter System

The BOP furnished engineered safety features support systems are:

7. Component Cooling Water System
8. Station Service Water System
9. Onsite Power Supply System
10. ESF Ventilation System
11. Safety Chilled Water System
12. Service Water Intake Structure Ventilation System
13. UPS Ventilation System (see Section 9.4C.8)

The ability to manually initiate operation of the systems described above is provided in accordance with IEEE-279-1971, Section 4.17.

The monitor light displays, located on the Control Board in the vicinity of the ESF system controls, provide an overview of the ESF functions. See Section 7.5.3.8.

In order to correspond with the NSSS criteria requirements to validate the assumptions and bases made in Chapter 15, Accident Analysis, instrumentation and control interface between the systems listed above and the NSSS is as follows:

The Engineered Safety Features Actuation System (ESFAS) is furnished by the NSSS vendor. It senses selected plant parameters and determines if predetermined safety limits are being exceeded or not. If they are, the ESFAS provides the contact closure outputs necessary to initiate those ESFS, including 1, 2, 4, 5, 7, 8, and 9 listed above, whose function best serves the requirements of the accident.

The ESFAS sensors, logic and initiating outputs to the various systems are per Figure 7.2-1. ESFAS sensors and other Class 1E instruments required for interlocks described below are located on Figure 7.1-3.

1. Containment Spray System

The CSS functions include containment cooling as well as fission product cleanup following a LOCA. The cooling function is described in Section 6.2.2 while the fission product cleanup function is in Section 6.5. The flow diagram is shown in Figure 6.2.2-1.

a. Initiating circuits

The Containment Spray System is initiated by either of the following signals:

1. Spray actuation signal (P signal)

2. Manual start from Main Control Board

The Containment Spray pumps are started by any of the following signals:

1. Spray actuation signal (P signal)

2. Safety injection sequence (S signal)

3. Manual start from Main Control Board

b. Logic

See Instrumentation & Control Diagrams listed under “Containment Spray System” in Tables 1.7-1 and 1.7-2.

c. Bypass

The Containment Spray System “bypass” is indicated on the Safety System Inoperable Indicator (SSII) described in Section 7.1.2.6 and illustrated typically in Figure 7.1-4.

d. Interlocks

The Containment Spray pumps cannot be started manually when the safety injection sequencing or blackout sequencing is in progress.

e. Redundancy

The Containment Spray System consists of two separate and independent full capacity safety-related loops, each capable of fulfilling the design requirements. Each train of the Containment Spray System is spatially and electrically separated.

f. Diversity

The Containment Spray System is actuated by such diverse signals as:

1. Spray actuation signal

2. Manual command.

g. Actuated devices

For a list of all devices actuated by the Containment Spray System see Table 7.3-5.

h. Supporting systems

1. Class 1E Electric Power (See Section 8.3)

2. Containment spray pump room fan coolers start upon a containment spray pump start (See Section 9.4.5)

3. Component Cooling Water System supplies cooling water to the containment spray pump seal coolers and to the containment spray heat exchangers (See Section 9.2.2)

4. Station Service Water System supplies cooling water to the containment spray pump bearings (See Section 9.2.1)

i. Design basis

See Section 6.2.2.1 for design basis information.

j. Electrical schematic drawings

See Table 1.7-1 for Unit 1 and 1.7-2 for Unit 2 schematics (electrical) associated with “Containment Spray.”

k. Portion of system not required for safety

Except for those instruments required for actuating Containment Spray System components listed in Table 7.3-5, or the safety related instrumentation described in Section 7.5 (Tables 7.5-7A, B & C), the instruments and monitoring equipment are not required for safety. Local indicators, plant computer points, plant annunciator and bypass monitoring systems are not required for safety.

l. Control of system operation

The spray additive tank discharge valves, initially opened by the spray actuation signal, are closed by actuation of level switches when the tank is emptied. The Containment Spray System is designed with on-off controls. Once the system is actuated, the pumps operate with constant flow.

m. Monitoring of system operation

The Containment Spray System is provided with Post Accident Monitors as described in Section 7.5. In addition, local indication is provided for spray-additive tank level and pressure, spray-additive flow and Containment Spray pump discharge pressure. The spray additive tank is provided with level indication, low-low level alarm, and a high/low pressure alarm in the Control Room. Additional Control Room alarms are provided for valve isolation tank high level, refueling water storage tank low temperature and spray additive low flow.

Each power operated valve is provided with position indicating lights in the Control Room. ESF monitor lights are provided for pumps and valves.

n. Sequencing

The sequencing of containment spray pumps upon loss of offsite power concurrent with a LOCA is shown in Table 8.3-1.

2. Containment Isolation System

Containment isolation is carried out in two phases: Phase A isolation closes all nonessential process lines penetrating the Containment, and Phase B isolation closes remaining process lines, except for those lines required for ESFAS. Containment Ventilation Isolation is initiated by Phase A isolation or a high containment radioactivity signal. The overriding of one type of safety actuation signal does not cause the blocking of any other type of safety actuation signal for those valves that have no function other than containment isolation. The Containment Isolation System is discussed in further detail in Section 6.2.4 and 7.3.1.1.5.

a. Initiating circuits

The initiating circuits for all Containment Isolation phases are shown on Figure 7.2-1, Sheet 8, and listed on Table 7.3-2, Item 1.

Phase A Isolation is initiated by the Safety Injection signal, as well as by manual actuation of Phase A isolation at the Control Board. Table 7.3-1, Item 1 lists the functions required to generate the Safety Injection signal.

Containment Ventilation Isolation is initiated by Phase A Isolation described above as well as by the Containment Spray Actuation manual controls on the Control Board, or high containment radioactivity (particulate or gas detectors). The instrumentation systems which initiate Containment Ventilation Isolation and are part of the ESFAS are qualified to Class 1E criteria.

Containment Ventilation Isolation occurs with an ESFAS “T” signal derived from three diverse variables. In addition, a non-safeguard, non-redundant, non-Class 1E radioactivity channel has also been added to the Containment Ventilation Isolation Logic. See Figure 7.2-1, Sheet 8, and Table 7.1-2, Safety Related Instrumentation and Control Systems/Codes, Standards and Guides/ Applicability Matrix.

The high radiation signal and a “T” signal, which provide input to Containment Ventilation Isolation, share a retentive-memory-with-actuation-block gate; however, the high radiation signal is a pulsed signal. If the gate was set because of a high radiation signal, resetting the gate after the pulse would not invoke the actuation-block feature; thus, making it receptive to a subsequent ESFAS “T” signal. See Figure 7.2-1, Sheet 8. This part of the CPNPP design was verified as part of the Preoperational Test Program.

Phase B Isolation is initiated by a “P” signal, generated by hi-3 containment pressure in 2 out of 4 channels, or by manual controls on the Control Board for Containment Spray actuation.

The discussion in 7.3.2.2.7 is referred to for the manual actuation switches described above. The manual Containment Isolation controls require simultaneous operation of two Control Board switches, as shown on Figure 7.2-1, Sheet 8.

b. Logic

The Containment Isolation logic is shown on Figure 7.2-1, Sheet 8. The design of the control systems for automatic containment isolation valves is such that resetting the isolation signal will not result in automatic reopening of the containment isolation valves. To reopen each containment valve requires deliberate operator action. In addition, See Tables 6.2.4-1, 2 and 3 for a complete list of Containment Isolation valves and their isolation signals.

c. Bypass

Some valves actuated by the Containment Ventilation Isolation signal or the Containment Isolation System can be manually operated from the Control Room, one at a time, by holding their control switches in the open or closed position, as applicable. The control switches for the isolation valves or dampers are of the spring-return-to-automatic type, so that as soon as the operator releases the switch, the component will again be returned to automatic control and the jurisdiction of the Containment Isolation System or the Containment Ventilation Isolation signal. This control switch feature provides adequate administrative control to ensure that the overriding of one type of safety actuation signal does not cause the blocking of any other type.

This manual override does not constitute a bypass of a protective function, as defined by IEEE-279, in that the channel is not removed from service. The component level manual override does not interfere with the protective function. This momentary manual override feature is not indicated on the Safety System Inoperable Indication System because it is apparent to the Control Room operator who is, in fact, performing the override function. (See Section 7.3.2.2.8).

Note that if the operator wanted to regain control over all components tripped by either the Containment Isolation or Containment Ventilation Isolation signals, he would do so by resetting the system-level actuation-block latch on ESFAS. See Figure 7.2-1, Sheet 8.

Also note that overriding or resetting an ESFAS signal does not cause any equipment to change position. Equipment must be subsequently reset at a lower level (e.g., at the individual component controls, by resetting the sequencer) before equipment will reposition. This was verified as part of the Preoperational Test Program.

d. Interlocks

Refer to discussion in Section 1A(B) regarding thermal overload interlocks for motor operated valves. There are no other interlocks associated with the Containment Isolation System.

e. Redundancy

The Containment Isolation redundancy requirements are satisfied by having two isolation barriers in series for Type A, Type B, and Type C penetrations (see Section 6.2.4.1.2). When two power operated isolation valves are in series, the power supply to the valves comes from separate and redundant buses. Failure of any one of two safety-related buses will not prevent Containment Isolation System from fulfilling its design requirements.

f. Diversity

There is some diversity associated with the generation of Phase A isolation signal, depending on which postulated event is assumed. Refer to discussion in Section 7.3.1.1.5, Item 2.

There is no diversity in the generation of Phase B isolation signal.

g. Actuated devices

The isolation valves relating to containment isolation are the actuated devices and are listed in Tables 6.2.4-1, 2, and 3.

h. Supporting systems

The Containment Isolation System is powered by two separate and independent Class 1E load centers, (See Section 8.3).

i. Design basis

Refer to Section 6.2.4.1 for design information.

j. Electrical schematic drawings

See Tables 6.2.4-1, 2 and 3 for a list of Containment Isolation valves and Tables 1.7-1 and 1.7-2 for electrical schematic drawings.

k. Portion of system not required for safety

Plant annunciator and plant computer are not required for safety.

l. Control of system operation

The Containment Isolation System is completely digital in nature, with on-off controls only. The manual system level control of the isolation function is provided by the Phase A, Phase B (Spray Actuation) and steamline isolation control board switches shown on Figure 7.2-1, Sheet 8.

In addition to the system level manual controls described above, each power-operated valve or damper is provided with a component-level control switch, with open, automatic and close positions. These switches spring return to the automatic position, through which the automatic containment isolation functions are achieved.

m. Monitoring of System Operation

Each component actuated by the Containment Isolation System has closed/not closed position indicating lights in the Control Room with the exception of specific containment isolation valves identified in Tables 7.5-7A and 7.5-7C. Containment

isolation valves whose method of actuation is “local-manual” have their stem position under direct observation when being operated.

In addition, a redundant backup is provided by monitor light displays. The monitor light displays provide a convenient overview of the isolation function, since all equipment actuated by a given isolation signal is grouped together.

n. Sequencing

This item is not applicable to the Containment Isolation System.

3. Item Deleted.

4. Control Room Air-Conditioning System

The Control Room Air-Conditioning System is discussed in Section 9.4-1. The system flow diagrams is shown in Figure 9.4-1.

a. Initiating Circuits

The Control Room Air-Conditioning system is started by any of the following signals:

1. Safety Injection Sequence (from either Unit 1 or Unit 2)

2. Blackout Sequence (from either Unit 1 or Unit 2)

3. Manual Start

b. Logic

See instrumentation and control diagrams listed under “Control Room Air-Conditioning” in Table 1.7-1.

c. Bypass

Bypass is indicated on Safety System Inoperable Indicator described in Section 7.1.2.6 and typically illustrated in Figure 7.1-4.

d. Interlocks

Control Room Air-Conditioning units cannot be started manually while Safety Injection Sequence or Blackout Sequence is in progress.

e. Redundancy

Separate system actuation switches and circuitry is provided for redundant system components. Physical and electrical separation is provided as discussed in Section 8.3.

f. Diversity

The Control Room Air-Conditioning System is started by such diverse signals as:

1. Safety Injection Sequence (from either Unit 1 or Unit 2)

2. Blackout Sequence (from either Unit 1 or Unit 2)

3. Manual Command

Control Room Emergency recirculation mode is started by such diverse signals as:

1. Safety Injection Signal (from either Unit 1 or Unit 2)

2. Blackout Sequence (from either Unit 1 or Unit 2)

3. High Radiation Concentration In The Intake Duct

4. Manual Command From Control Room

Control Room Isolation Mode is started by:

1. Manual Action

Control Room Emergency Ventilation Mode is started manually from the Control Room only when Emergency recirculation signal is present.

g. Actuated Devices

1. For a list of devices actuated within the Control Room Air-Conditioning System, by the Safety Injection signal refer to Table 7.3-4.

2. For devices actuated directly by the Control Room Air- Conditioning System see associated instrumentation and control diagrams listed in Table 1.7-1.

h. Supporting Systems

The systems required for proper air-conditioning operation are:

1. Class 1E Electric Power (See Section 8.3)

2. Component Cooling Water (See Section 9.2.2)

i. Design Basis

For information concerning basis of design refer to Section 9.4.1.1.

j. Electrical Schematic Drawings

See Table 1.7-1 for schematics (electrical) associated with “Control Room and Office Facility HVAC.”

k. Portion of System Not Required For Safety

Except for those instruments required for actuating the Control Room Air Conditioning System and components listed in Table 7.3-4, local indicators, the plant annunciator, the plant computer and the bypass indication system are not required for safety.

l. Control of System

There are four modes of operation: Normal Operation, Emergency Ventilation, Isolation and Emergency Recirculation. For each mode of operation, the final status of fans and dampers is indicated in Figure 9.4-1.

For the Normal Operating Mode, starting of the fans and actuation of dampers are carried out manually by the operator from the Control Room. Design ambient conditions of the Control Room are maintained by the air-conditioning units. Slightly positive Control Room pressure is maintained by throttling the exhaust dampers.

The Control Room Air-Conditioning system will be automatically switched to Emergency Recirculation Mode on receipt of any of the following signals:

1. Control Room Intake Duct Radiation Hi

2. Safety Injection (from either Unit 1 or Unit 2)

3. Blackout Sequence (from either Unit 1 or Unit 2)

Emergency Recirculation can also be manually initiated.

m. Monitoring of System Operation

System component status indicating lights, system failure alarms, Control Room to outside environs differential pressure indicator, and Control Room area radiation monitors are provided in the Control Room to enable the operator to evaluate the system performance.

n. Sequencing

The sequencing of the Control Room Air-Conditioning upon loss of offsite power concurrent with a LOCA is shown in Table 8.3-1.

5. Auxiliary Feedwater System

The Auxiliary Feedwater System is outlined in Subsection 10.4.9. The system flow diagram is shown in Figure 10.4-11.

a. Initiating Circuits

The motor-driven pumps are started by any of the following signals:

1. Safety Injection Sequence
2. Blackout Sequence
3. Trip of both main feedwater pumps (pumps 1-A and 1-B)
4. Steam generator low-low level (two of four from any steam generator)
5. Manual start (from Control Room or Hot Shutdown Panel)
6. AMSAC

The turbine-driven pump is started by any of the following signals:

1. Steam generators low-low level (two of four from any two steam generators)
2. Blackout (loss of voltage) signal
3. Manual start (from Control Room or Hot Shutdown Panel)
4. AMSAC

The auto start signals that starts any of the three auxiliary feedwater pumps closes the blowdown and sample line isolation valves for all the steam generators, and closes the condensate makeup and reject line isolation valves and the Unit 2 feedwater split flow bypass valves.

b. Logic

See instrumentation and control diagrams listed under “Auxiliary Feedwater” in Tables 1.7-1 and 1.7-2.

c. Bypass

Bypass is indicated on Safety System Inoperable Indicator (SSII) described in Section 7.1.2.6 and generally illustrated in Figure 7.1-4.

d. Interlocks

1. The operator lockout (OL) or automatic lockout (AL) feature of the sequencer can, on the appearance of a safety injection or blackout signal, annul either manual or autostart of the AFW System motor-driven pumps in order to properly sequence them on the diesel. For local override control at the Hot Shutdown Panel refer to Section 7.4.1.3.1.

2. Automatic starts of the Auxiliary Feedwater System also close the steam generator blowdown isolation and sample line isolation valves, and close the condensate makeup and reject line isolation valves and the Unit 2 feedwater splitflow bypass valves.

e. Redundancy

Steam admission valves and controls for turbine drive are redundant. (See instrumentation and control drawings listed in Section 1.7)

Motor-driven pumps controls and instrumentation are redundant.

Steam Generator level measurement is quadruplicated. (See Figure 7.2-1, Sheet 7)

Auxiliary feedwater flow to each steam generator is redundant (See Figure 7.3-4)

f. Diversity

The AFW System is started by such diverse signals as:

1. Trip of Both Main FW Pumps

2. Steam Generator Low-Low Level

3. Safety Injection Sequence

4. Blackout Sequence

5. Manual Command at Either the Control Room or Hot Shutdown Panel (See Figure 7.2-1, Sheet 15).

6. AMSAC

g. Actuated Devices

Actuated devices are listed in Table 7.3-4.

h. Supporting Systems

The following support systems are required by the AFW System:

1. Class 1E Electric Power (See Section 8.3)

2. Engineered Safety Features Ventilation System (See Section 9.4.5 and Figure 9.4-4)

3. Safety Chilled Water System (See Section 9.4F).

i. Design Basis

See Section 10.4.9.1 for the design bases of the AFW System.

j. Electric Schematic Drawings

See Table 1.7-1 for Unit 1 and Table 1.7-2 for Unit 2 schematics (electrical) associated with “Auxiliary Feedwater.”

k. Portion of System Not Required For Safety

Except for those instruments required for actuating Auxiliary Feedwater System components listed in Table 7.3- 4, or the safety-related instrumentation described in Section 7.5 (Tables 7.5-7A, B & C), the instruments and monitoring equipment are not required for safety. Local indicators, plant computer points, plant annunciator and bypass monitoring systems are not required for safety.

l. Control of System Operation

The AFW System is used for startup when there is no steam to drive the feedwater pumps, for shutdown until the hot-leg temperature is down to 350°F, at which time the RHR System goes into operation, or following the receipt of any of the automatic signals described above.

Pneumatically operated flow control valves are provided downstream of the motor and steam turbine driven AFW pumps to maintain water level in the steam generators.

The pneumatically operated flow control valves downstream of the motor driven pumps are automatically tripped to full open position on auto start of the pump. After the initial lock out the valves are manually controlled from the Control Room.

The normally open pneumatically operated flow control valves downstream of the steam turbine driven pump are manually controlled from the control room.

All other valves in the system with the exception of the steam admission valves to the auxiliary feed pump turbine are normally in the ready position to permit auxiliary feedwater flow.

The pumps deliver full flow upon receipt of the actuation signal. See section 10.4.9 for additional details.

The steam admission valves, normally closed, will open upon receipt of the actuation signal.

Protection against excessive flow to containment and pump runout in the event of a drop in the steam generator pressure is provided by the flow orifices located on the pump discharge lines.

m. Monitoring of System Operation

The AFW System is provided with display instrumentation as follows:

1. Steam Generator Level (Accident Monitors, Type A, B and D variables, see Tables 7.5-2, 3, 5)

2. Auxiliary Feedwater Flow To Each Steam Generator (Accident Monitors, Type A, B, D variables, Tables 7.5-2, 3, 5).

3. Pump Flow

4. Pump Discharge Pressure

5. Pump Suction Pressure

6. Condensate Storage Tank Level (Accident Monitors, Type A, D variables, see Tables 7.5-2, 5)

n. Sequencing

The sequencing of motor-driven AFW pumps upon loss of offsite power concurrent with a LOCA is shown in Table 8.3-1.

6. ESF Filter System

The ESF Filter System is described in Section 6.5.1. Figure 6.5-1 illustrates a typical layout for the ESF filter units.

a. Initiating Circuit

No automatic initiating circuit is provided. ESF filters are passive components. Inlet dampers, exhaust fans and filter assembly heaters for primary plant ESF exhaust filters are started either manually or by a Safety Injection Actuation Signal from either Unit 1 or Unit 2. Inlet dampers, exhaust fans and filter assembly heaters for the Control Room Emergency Pressurization and Emergency Filtration units are started either manually or by Control Room Emergency Recirculation signal. Heaters are not included in Control Room Emergency filtration units.

b. Logic

See instrumentation and control diagram listed under “Control Room Air-Conditioning”, and “Ventilation Equipment Primary Plant” listed in Table 1.7-1.

c. Bypass

There are no bypasses associated with this system.

System level SSII for Control Room Emergency Pressurization and Emergency Filtration Units is “Control Room HVAC” and System level SSII for ESF exhaust filtration units is “Primary Plant ESF Ventilation Exhaust”.

d. Interlocks

There are no interlocks associated with this system.

e. Redundancy

Redundant ESF filters are provided which are physically and electrically separated from one another.

f. Diversity

Control Room Emergency Pressurization and Emergency Filtration Units inlet dampers, exhaust fans and associated filter assembly heaters are started by such diverse signals as:

1. Control Room Emergency Recirculation Signal

2. Manual Command at Control Room.

g. Actuated Devices

1. ESF Filter Inlet Dampers

2. ESF Filter Exhaust Fans

3. ESF Filter Assembly Heaters

h. Supporting System

ESF Filter System is supported by Class 1E electric power (See Section 8.3).

i. Design Basis

See Section 6.5.1.1 for the design basis of ESF Filter System.

j. Electric Schematic Drawings

See Table 1.7-1 for schematics (electrical) associated with “Control Room and Office Facility HVAC” and “Primary Plant Ventilation.”

k. Portions of System Not Required For Safety

Except for those instruments required to actuate the ESF Filter System components listed in Item g above, or the safety-related instrumentation described in Section 7.5 (Tables 7.5-7A, B & C), the instruments and monitoring equipment are not required for safety. Local indicators, plant computer points, plant annunciator and bypass monitoring systems are not required for safety.

l. Control of System Operation

All ESF Filter System components necessary for operation are controlled from the Control Room. Temperature detection components provide Hi and Hi-Hi temperature information in the fire protection panels located in the same building as the corresponding filter units. These fire protection panels provide Hi and Hi-Hi temperature alarm and trouble alarm information to the Control Room.

m. Monitoring of System Operation

Each ESF filter and exhaust fan are supplied with differential pressure alarms to alert the Control Room operator of a fan malfunction or a clogged filter. Local pressure indicators are provided to monitor the resistance of each individual filter bank. Each adsorber bed has a temperature monitoring system which indicates bed temperature and actuates a high temperature alarm in the Control Room. System component status indicating lights are provided in the Control Room.

n. Sequencing

The sequencing of the primary plant ESF filter units upon loss of offsite power concurrent with a LOCA is shown in Table 8.3-1.

7. Component Cooling Water System

The Component Cooling Water (CCW) System is discussed in Section 9.2.2. The System flow diagram is shown in Figure 9.2-3.

a. Initiating Circuits

The Component Cooling Water pumps are started by any of the following signals:

1. Safety Injection Sequence

2. Blackout Sequence

3. Service Water Pump Auto Start On Low Pressure

4. Low Pressure In The Discharge Header Of Redundant Component Cooling Water Pump.

5. Manual Start (From Control Room or Hot Shutdown Panel)

b. Logic

See instrumentation and control diagram listed under “Component Cooling Water” in Tables 1.7-1 and 1.7-2.

c. Bypass

Bypass is indicated on Safety System Inoperable Indicator described in Section 7.1.2.6 and typically illustrated in Figure 7.1-4.

d. Interlocks

The Component Cooling Water pumps cannot be started either manually or automatically when the Safety Injection Sequencing or Blackout Sequencing is in progress. For local override control at the Hot Shutdown Panel, refer to Section 7.4.1.3.1.

e. Redundancy

Separate switches and actuation circuitry are provided for redundant components which are physically and electrically separated from one another.

f. Diversity

The Component Cooling System is started by such diverse signals as:

1. Safety Injection Sequence

2. Blackout Sequence

3. Service Water Pump Autostart On Low Pressure

4. Low Pressure In The Discharge Header of Redundant Component Cooling Water Pump.

5. Manual Command At Either The Control Room or Hot Shutdown Panel.

g. Actuated Devices

Actuated devices are listed in Table 7.3-4, (for all equipment actuated by “s” signal) and Table 7.3-5 (for all equipment actuated by “p” signal).

h. Supporting Systems

The following support systems are required by the Component Cooling Water System:

1. Station Service Water System (See Section 9.2.1)

2. Class 1E Electric Power (See Section 8.3)

3. Engineered Safety Features Ventilation System (See Section 9.4.5 and Figure 9.4-2, Sheet 1).

i. Design Basis

See Section 9.2.2.2.2 for the design basis of the Component Cooling Water System.

j. Electric Schematic Drawings

See Table 1.7-1 for Unit 1 and Table 1.7-2 for Unit 2 schematics (electrical) associated with “Component Cooling Water.”

k. Portion of System Not Required For Safety

Except for those instruments required to actuate the Component Cooling Water System components listed in Table 7.3-5 or the safety related instrumentation described in Section 7.5 (Tables 7.5-7A, B & C), the instruments and monitoring equipment are not required for safety. Local indicators, the plant annunciator and the plant computer are also not required for safety.

l. Control of System Operation

The CCW System is designed as an on/off system during normal operation. Pump recirculation valves are provided to maintain required minimum pump flow under abnormal conditions.

The CCW pumps are automatically started by low pressure in the pump discharge header.

The CCW surge tank level is used to detect system leakage. The control system for each half of each partitioned tank consists of the following:

1. Level Indication - Local and Control Room

2. Level Recording

3. Hi-Hi/Lo Alarms

4. Automatic Make-up From Reactor Make-Up Water on Lo-Lo Level

5. Automatic Make-Up “Initiated” Alarm

6. Automatic Make-Up Termination On Hi-Level

7. Manual Make-up From Demineralized Water.

8. Automatic train separation on Empty Level

m. Monitoring of System Operation

The CCW System is provided with monitoring instrumentation as described in Table 7.5-7A and B. In addition, each component is supplied with local temperature indication. Sufficient local flow indication is provided to allow flow balancing of the system. Each flow indicator has a low flow alarm contact to alert the operator of a system malfunction. Flow indication is provided in the Control Room for Containment Spray and RHR heat exchangers.

Each power operated valve is supplied with a control switch and position indicating lights in the Control Room.

Radiation monitors are provided with readout in the Control Room for each of the three loops in each subsystem.

n. Sequencing

The sequencing of CCW pumps upon loss of offsite power concurrent with a LOCA is shown in Table 8.3-1.

8. Station Service Water

The Station Service Water (SSW) System is discussed in Section 9.2.1. The System Flow diagram is shown in Figure 9.2-1.

a. Initiating Circuits

The Station Service Water System is started by any of the following signals:

1. Safety Injection Sequence

2. Blackout Sequence

3. Component Cooling Water Pump Start Signal

4. Low Pressure Signal of Train B Supply Header Starts Train A Service Water Pump and Vice Versa.

5. Manual Command Either at Control Board or at Hot Shutdown Panel.

b. Logic

See instrumentation and control diagrams listed under “Station Service Water System” in Tables 1.7-1 and 1.7-2.

c. Bypass

Station Service Water System Bypass is indicated on the Safety System Inoperable Indicator (SSII) described in Section 7.1.2.6 and typically illustrated in Figure 7.1-4.

d. Interlocks

The Station Service Water pumps cannot be started either manually or automatically when the Safety Injection Sequencing or Blackout Sequencing is in progress. For local override control at the Hot Shutdown Panel, refer to Section 7.4.1.3.1.

e. Redundancy

Separate switches and actuation circuitry are provided for redundant components which are physically and electrically separated from one another.

f. Diversity

The Service Water System may be controlled from the following locations:

1. Each Service Water pump may be controlled by:

   (a) A Control Switch on the Main Control Board

   (b) A Local Control Switch on the Hot Shutdown Panel

   (c) Blackout Sequence

   (d) Safety Injection Sequence

   (e) Component Cooling Water Pump Start Signal

In addition to above, low pressure signal of Train B supply header starts Train A Service Water pump and vice versa.

g. Actuated Devices

For devices actuated directly by the “S” signal see Table 7.3-4.

For devices actuated directly by the Station Service Water System, refer to Station Service Water instrumentation and control drawings listed in Tables 1.7-1 and 1.7-2.

h. Support Systems

The Service Water System is supported by:

1. Class 1E Electric Power (See Section 8.3)

2. Service Water Intake Structure Ventilation Exhaust System (See Section 9.4B and Item 6 below)

i. Design Basis

For information concerning basis of design see Section 9.2.1.1.

j. Electrical Schematic Drawings

See Table 1.7-1 for Unit 1 and 1.7-2 for Unit 2 schematics (electrical) associated "Station Service Water."

k. Portion of System Not Required for Safety

Except for those instruments required for actuating Service Water System components listed in Table 7.3-4, or the safety-related instrumentation described in Section 7.5 (Tables 7.5-7A, B & C), the instruments and monitoring equipment are not required for safety. Local indicators, plant computer points, plant annunciator and bypass monitoring systems, are not required for safety.

l. Control of System Components

The SSW System is designed to operate with a constant system pressure during normal operation.

m. Monitoring of System Operation

The SSW System is provided with monitoring instrumentation as described in Section 7.5. In addition, each component is provided with local temperature indication. Sufficient local flow indication is provided to allow flow balancing of the system.

Each power operated valve is supplied with a control switch and position indicating lights in the Control Room.

Radiation monitors are provided with readout in the Control Room for each of the return headers of the CCW system.

n. Sequencing

The sequencing of SSW pumps upon loss of offsite power concurrent with a LOCA is shown in Table 8.3-1.

9. Onsite Power Supply System

The Onsite AC Power Supply System is discussed in Section 8.3. Two independent diesel generators are provided for each unit. The starting and loading diagrams for the diesel generators are shown in Figure 8.3-3.

The station DC systems provide power for the plant instrumentation and control under all modes of plant operation. For details see Section 8.3.2.

a. Initiating Circuits

AC - Starting of diesel generator sets, automatic stripping and loading of buses are discussed in Section 8.3.1.1.5.

DC - The DC power supplies are designed to be continuously available during all modes of plant operation. Thus, no initiating circuits are required.

b. Logic

AC - See Figure 8.3-3.

DC - See Figure 8.3-14.

c. Bypass

AC - Bypass is indicated on Safety System Inoperable Indicator (SSII) described in Section 7.1.2.6 and typically illustrated in Figure 7.1-4.

DC - The system is indicated on Safety System Inoperable Indicator (SSII) as described in Section 7.1.2.6 and typically illustrated in Figure 7.1-4.

d. Interlocks

AC - See Section 8.3.1.1.11, item 2.

DC - Normally, one battery charger is operating and the other is kept as a spare. The circuit breakers connecting these battery chargers to the DC distribution bus are mechanically interlocked such that only one battery charger remains connected to the bus at any time. For details see Section 8.3.2.1, Item 2b.

e. Redundancy

AC - Separate control switches and actuation circuitry are provided for starting each emergency diesel generator and actuating emergency bus breakers. The Standby Power System consists of redundant diesel generator sets, each having redundant air starting systems and fuel transfer systems. DC power from a redundant battery system furnishes power for the circuitry. The DC system is described in Section 8.3.2.

DC - Two independent and redundant 125V DC systems are provided for each unit. Each system consists of two batteries, each having one main distribution bus with molded case circuits breakers and fusible switches, two static battery chargers (one spare) and local distribution panels (see Figures 8.3-14 and 8.3-15B).

f. Diversity

AC - The diesel generators are actuated by such diverse signals as:

1. Safety Injection Signal

2. Undervoltage On Its Respective Emergency Bus

3. Manual Command.

DC - A spare battery charger is provided for each DC system battery.

g. Actuated Devices

AC - Actuated devices are diesel generator sets which are listed in Table 7.3-4.

DC - No devices require actuation in this system.

h. Supporting Systems

AC - Protection systems, diesel generator fuel oil storage and transfer system, cooling and heating system, Lube Oil System, Combustion Air Intake and Exhaust System and Ventilation System for the Standby Power System are discussed in Sections 8.3.1.1.11, 9.5.4, 9.5.5, 9.5.7, 9.5.8, and 9.4C, respectively.

DC - Battery chargers and ventilation systems are described in Section 8.3.2.1, Items 2b and 3.

i. Design Basis

AC - See Section 8.3.1 for the design basis of Onsite Power Supply System.

DC - See Section 8.3.2.

j. Electric Schematic Drawings

AC - See Table 1.7-1 for Unit 1 and Table 1.7-2 for Unit 2 schematics.

DC - See Figure 8.3-14

k. Portion of System Not Required For Safety

AC - Local indicators and annunciator system are not required for safety.

DC - Local indicators and annunciator system are not required for safety.

l. Control of System Operation

AC - Once the system is actuated, the diesel generator voltage and frequency are automatically controlled.

Each diesel generator set has its own speed control system and voltage regulator. Manual controls are not necessary for proper system functioning. Manual backup for voltage and frequency controls are provided locally and in the Control Room. Control switches are also provided locally and in the Control Room for manually starting the diesel generators and operating the generator breakers. Once the diesel generator is started in emergency mode, shutdown can only be accomplished by operator's manual action, except under generator differential protection operation, and overspeed protection.

DC - Except for adjusting battery charger voltage for periodic equalizing charge, no other manual or automatic controls are required. For details see Section 8.3.2.1.

m. Monitoring of System Operation

AC - Control Room indication, alarm and status instrumentation are provided to enable the operator to evaluate system performance and detect malfunctions. Diesel generator current, voltage, and frequency are indicated. Alarms are provided to indicate diesel generator malfunction or trip.

Instrumentation and control systems are provided as discussed in Section 8.3.1.1.7.

DC - Battery float and discharge current and distribution bus voltage are monitored at the switchboard and in the Control Room. For details, see Section 8.3.2.2, Item 1.

n. Sequencing

This is not applicable to the Onsite Power System.

10. ESF Ventilation System

The ESF Ventilation System is discussed in Section 9.4.5. The system flow diagram is shown in Figure 9.4-4.

a. Initiating Circuit

Emergency fan coil units of safety-related pump rooms are started either manually or by the start signal from the equipments they serve. Emergency fan coil units for electrical area are started manually or automatically. Diesel oil day tank area ventilation fans are started either manually or by the start signal from the diesel generator.

b. Logic

See instrumentation and control diagram listed under “Ventilation Safeguards and Electrical Area” listed in Table 1.7-1 for Unit 1 and Table 1.7-2 for Unit 2.

c. Bypass

Bypass is indicated on Safety System Inoperable Indicator (SSII) described in Section 7.1.2.6 and typically illustrated in Figure 7.1-4.

d. Interlocks

There are no interlocks in this system.

e. Redundancy

Redundant fan coil units and redundant diesel oil day tank area ventilation fans are powered from redundant electric power trains.

f. Diversity

Fan coil units for safety-related pump rooms and diesel oil day tank area ventilation fans are started by such diverse signals as:

1. Start Signal From the Equipment They Serve

2. Manual Command Either at Control Room or Local Switch Station.

Fan coil units for electrical area are started by such diverse signals as:

1. Manual Command either at Control Room or locally

2. Safety Injection Sequence

3. Blackout Sequence

g. Actuated Devices

1. Emergency Fan Coil Units for Safety-Related Pump Rooms

2. Emergency Fan Coil Units for Electrical Area

3. Diesel Oil Day Tank Area Ventilation Fans

h. Supporting System

ESF Ventilation System is supported by Class 1E electric power (See Section 8.3) and the Safety Chilled Water System (See Section 9.4F).

i. Design Basis

See Section 9.4.5.1 for the design basis of ESF Ventilation System.

j. Electrical Schematic Drawings

See Table 1.7-1 for Unit 1 and Table 1.7-2 for Unit 2 schematic (electrical) associated with “Safeguard and Electrical Area Ventilation.”

k. Portion of System Not Required For Safety

Remote and local indications, Safeguard Building electrical area exhaust and supply fans, Safeguard Buildings main steam and feedwater exhaust and supply fans, room supply and exhaust dampers, fan heaters and the plant annunciator are not required for safety.

l. Control of System Operation

The ESF Ventilation System components necessary for operation are controlled from the Control Room. In addition, the emergency fan coil units of safety-related pump rooms can be controlled by local control. Each set of room supply dampers and exhaust valves is provided with a control switch and position indicating lights in the Control Room.

m. Monitoring of System Operation

Each safety-related pump room is provided with local temperature indicator and a Hi/Lo temperature alarm in the Control Room. Electrical area is also provided with temperature indicators mounted near the fan coolers and Hi-Hi temperature alarms in the Control Room. Transfer of controls of fan coil units from remote to local actuates an alarm in the Control Room. System component status indicating lights are provided in the Control Room.

n. Sequencing

The sequencing of the emergency fan coil units upon loss of offsite power concurrent with a LOCA is shown in Table 8.3-1.

11. Safety Chilled Water System

The Safety Chilled Water System is described in Section 9.4F. The System flow diagram is shown in Figure 9.4-12.

a. Initiating Circuit

The Safety Chilled Water recirculation pumps are started by any of the following signals:

1. Safety Injection Sequence

2. Blackout Sequence

3. Manual Start From Control Room

4. Start of CCW Pump

5. Manual Start From HSP For “A” Train Pump

b. Logic

See instrumentation and control diagrams listed under “Ventilation Safety Chilled Water” in Tables 1.7-1 and 1.7-2.

c. Bypass

Bypass is indicated on Safety System Inoperable Indicator described in Section 7.1.2.6 and typically illustrated in Figure 7.1-4.

d. Interlocks

Chilled water recirculation pumps cannot be started manually while Safety Injection Sequence or Blackout Sequence is in progress. For local override control at the Hot Shutdown Panel, refer to Section 7.4.1.3.1.

e. Redundancy

Separate switches and actuation circuitry are provided for redundant components which are physically and electrically separated from one another.

f. Diversity

The Safety Chilled Water Recirculation pumps are started by such diverse signals as:

1. Safety Injection Sequence

2. Blackout Sequence

3. Manual Command at the Control Room.

4. Start of CCW Pump

5. Manual Start From HSP For “A” Train Pump

g. Actuated Devices

1. Safety Chilled Water Recirculation Pumps

2. Water Chillers

h. Supporting Systems

The following supported systems are required by the Safety Chilled Water System:

1. Class 1E Electric Power (See Section 8.3)

2. Component Cooling Water (See Section 9.2.2).

i. Design Basis

See Section 9.4F.1 for the design basis of the Safety Chilled Water System.

j. Electric Schematic Drawings

See Table 1.7-1 for Unit 1 and Table 1.7-2 for Unit 2 schematic (electrical) associated with “Ventilation Chilled Water and Safety Chilled Water.”

k. Portion of System Not Required For Safety

The following portions of the Safety Chilled Water System are not required for safety:

1. Remote and Local Indicator

2. Plant Annunciators

3. Plant Computer

4. Inlet valves to surge tank from reactor make-up storage tank and demineralized water storage tank.

l. Control of System Operation

The Safety Chilled Water System is designed as an on/off system during normal operation.

Surge tank level is used to monitor the system for leakage. The control system for each half of the partitioned surge tank consists of the following:

1. Level indication - local

2. Hi-Hi/Lo-Lo alarm

3. Automatic make-up from demineralized or reactor makeup water on lo level

4. Automatic make-up termination on Hi level

5. Manual make-up from demineralized or reactor make-up water.

Each power operated valve is supplied with a control switch and position indicating lights in the Control Room.

m. Monitoring of System Operation

The Safety Chilled Water System is provided with display instrumentation and monitoring as follows:

1. Pump discharge pressure indication - local

2. Low pump discharge pressure alarm in the Control Room

3. Evaporator package discharge temperature local indications, discharge flow indication and Lo-flow alarm in the Control Room.

4. Surge tank level indication - local

5. Emergency fan coil unit temperature - local

6. Status lights in the Control Room for Safety Chilled Water recirculation pumps and all power operated valves.

n. Sequencing

The sequencing of safety chilled water pumps upon loss of offsite power concurrent with a LOCA is shown in Table 8.3-1.

12. Service Water Intake Structure Ventilation

The Service Water Intake Structure Ventilation is described in Section 9.4B and the flow diagram is shown in Fig. 9.4-7.

a. Initiating circuit

Service Water pump area exhaust system is started manually by the intake structure operator or automatically by locally mounted temperature switches.

b. Logic

See instrumentation and control diagrams listed under “Ventilation Service Water Intake Structure and Misc. Building” in Table 1.7-1.

c. Bypass

There are no bypasses associated with this system.

d. Interlocks

There are no interlocks in this system.

e. Redundancy

Separate switches and actuation circuitry are provided for redundant exhaust fans which are physically and electrically separated from one another.

f. Diversity

Service Water Intake Structure area fans are started manually by the intake structure operator or automatically by locally mounted temperature switches. Status of the fans are indicated both locally and remotely on the Control Board.

g. Actuated devices

Service Water Intake Structure area fans

h. Supporting system

Service Water Intake Structure Ventilation is supported by Class 1E electric power (See Section 8.3).

i. Design basis

See Section 9.4B.1 for the design basis of Service Water Intake Structure Ventilation System.

j. Electric schematic diagram

See Table 1.7-1 for schematic (electrical) associated with “Service Water.”

k. Portion of system not required for safety

Local indication and alarms are not required for safety.

l. Control of system operation

The HVAC System for the Service Water Intake Structure is designed to maintain the ambient temperature within the structure as indicated in Section 9.4B.1. A

local start, stop, spring-return-to-auto switch is available for exhaust fan control. In addition, six non-safety-related, thermostatically controlled, unit heaters are provided for winter service. Generally, exhaust fan operation is not required during the winter.

m. Monitoring of system operation

Exhaust fan “Start”, “Stop”, and “Trip” is indicated in the Control Room for each fan. In addition, fan “Trip” is alarmed in the Control Room.

A “High” and “Lo-Lo” temperature alarm is available in the Control Room derived from local temperature indicating switches. In addition, a combined unit heater trip alarm is available in the Control Room.

n. Sequencing

This Load is not sequenced automatically. The fans start automatically by locally mounted temperature switches. See Table 8.3-1.

13. UPS Ventilation System

The UPS Ventilation System is discussed in Section 9.4C.8. The System Flow diagram is shown in Figure 9.4-15.

a. Initiating circuits

The UPS Ventilation System is started by any of the following signals:

1. Safety Injection Sequence (from either Unit 1 or Unit 2)

2. Blackout Sequence (from either Unit 1 or Unit 2)

3. Temperature Switches located in the UPS and Distribution Room

4. Manual command at Control Board.

b. Logic

See instrumentation and control diagrams listed under “UPS Ventilation System” in Table 1.7-1.

c. Bypass

There are no bypasses associated with this system.

d. Interlocks

The UPS Ventilation A/C units and fans cannot be started manually from the Control Panel when the Safety Injection Sequencing or Blackout Sequencing is in progress.

e. Redundancy

Separate switches and actuation circuitry are provided for redundant components which are physically and electrically separated from one another.

f. Diversity

A/C units and fans are started by such diverse signals as:

1. Safety Injection Sequence (from either Unit 1 or Unit 2)

2. Blackout Sequence (from either Unit 1 or Unit 2)

3. Temperature switches located in the Unit 1 and Unit 2 UPS and distribution rooms.

4. Manual command from Control Room or local control switch.

g. Actuated devices

For devices actuated directly by the “S” signal see Table 7.3-4.

For devices actuated directly by the UPS Ventilation System, refer to UPS Ventilation System instrumentation and control drawings listed in Table 1.7-1 and 1.7-2.

h. Support Systems

The UPS Ventilation System is supported by:

1. Class 1E electric power (See Section 8.3)

2. Component Cooling Water System (See Section 9.2.2)

i. Design basis

For information concerning basis of design see Section 9.4C.8.

j. Electrical schematic drawings

See Table 1.7-1, “BOP Misc. Systems” for the schematics (electrical).

k. Portion of system not required for safety

Except for those instruments required for actuating UPS Ventilation System components listed in Table 7.3-4, the instruments and monitoring equipment are not required for safety. Local indicators, plant annunciator and bypass monitoring systems, are not required for safety.

l. Control of system components

The UPS Ventilation system is designed to remove heat rejected by both Unit 1 and Unit 2 UPS inverters and chargers to maintain ambient temperature below design limits. During normal operation, one train is in service with the opposite train in standby.

m. Monitoring of system operation

UPS Ventilation A/C Unit and fan status monitoring lights, A/C fan and the booster return fan differential pressure alarms, and UPS and distribution room high temperature alarm are provided for the monitoring of system operation.

n. Sequencing

The sequencing of the UPS Ventilation A/C units and fans upon loss of offsite power concurrent with a LOCA is shown in Table 8.3-1.

7.3.1.1.5 Final Actuation Circuitry

The outputs of the Solid State Logic Protection System (the slave relays) are energized to actuate, as are most final actuators and actuated devices. These devices are listed as follows:

1. Emergency Core Cooling. Refer to Section 6.3 and Figure 7.2-1 for flow diagrams and additional information.

2. Containment isolation Phase A is by a “T” signal which isolates all nonessential process lines on receipt of the safety injection signal, as well as by manual actuation of Phase A containment isolation at the control board. The process parameters which are relied on for deriving the safety injection signal are listed under Item 1 of Table 7.3-1 and their performance requirements are discussed in Section 7.3.1.2.6. For a given design condition, there is an initial containment isolation function derived from a primary generating station variable. For example, for a primary system accident (see Section 7.3.1.2.2), containment isolation is initially derived from low pressurizer pressure. However, another containment isolation function may be derived from high-1 containment pressure during the course of a postulated accident and depending on what postulated event is assumed. Criteria to provide diversity is not a requirement, but as indicated in the forgoing, some may be available for Phase A containment isolation.

   Containment isolation Phase B is by a “P” signal which isolates the remaining process lines (which do not include safety injection lines) on receipt of two out of four Hi-3 containment pressure signal. For further information, refer to Section 6.2.4.

3. Service water pump and valve actuators (see Section 7.3.1.1.4 and 9.2.1)

4. Auxiliary feedwater pumps start (see Sections 7.3.1.1.4 and 10.4.9)

5. Diesel start (see Sections 7.3.1.1.4.6 and Chapter 8)

6. Feedwater isolation (see Section 10.4.7.3 and Fig. 7.2-1)

7. Control Room Ventilation isolation valve and damper actuators (see Section 7.3.1.1.4.7, Section 9.4.1.1, and Table 9.4-10)

8. Steamline isolation valve actuators (see Section 10.3 and Fig. 7.2-1)

9. Containment spray pump and valve actuators (see Sections 7.3.1.1.4 and 6.2.2)

Power interruption to the engineered safety features system in conjunction with a LOCA or other postulated accident is a highly improbable event. To satisfy GDC 35 requirements, accident analyses assume a loss of offsite power coincident with certain postulated events such as a LOCA, steam line break, and feedline break (see Chapter 15). It is also assumed that a single failure occurs which causes the loss of one of the two onsite emergency diesel generators. In the unlikely event that a loss of offsite power were to occur following the onset of a LOCA or other accident, the consequences could be mitigated by administrative procedures. If an accident is assumed to occur coincident with loss of offsite power, the engineered safety features loads must be sequenced onto the diesel generators to prevent overloading them. This sequence is discussed in Chapter 8. The design meets the requirements of Criterion 35 of the 1971 GDC.

7.3.1.2 Design Basis Information

The functional diagrams presented in Figure 7.2-1, Sheets 5, 6, 7 and 8 provide a graphic outline of the functional logic associated with requirements for the ESF Systems. Additional requirements for the Engineered Safety Features System are given in Chapter 6. Given below is the design bases information required in IEEE Standard 279- 1971 Reference [4].

7.3.1.2.1 Generating Station Conditions

The following is a summary of those generating station conditions requiring protective action:

1. Primary System

   a. Rupture in small pipes or cracks in large pipes

   b. Rupture of a reactor coolant pipe (loss of coolant accident)

   c. Steam generator tube rupture

2. Secondary System

   a. Minor secondary system pipe breaks resulting in steam release rates equivalent to flow through a single dump, relief or safety valve

   b. Rupture of a major steam pipe.

7.3.1.2.2 Generating Station Variables

The following list summarizes the generating station variables required to be monitored for the automatic initiation of safety injection during each accident identified in the preceding section. Post-accident monitoring requirements are given in Table 7.5-1.

1. Primary System accidents

    a. Pressurizer pressure

    b. Containment pressure (not required for steam generator tube rupture)

2. Secondary System accidents

    a. Pressurizer pressure

    b. Steam line pressures and steam line pressure rates

    c. Containment pressure

7.3.1.2.3 Spatially Dependent Variables

The ESFAS has no inputs derived from direct measurements of the desired variables that have spatial dependence.

7.3.1.2.4 Limits, Margins and Levels

Prudent operational limits, available margins and setpoints before onset of unsafe conditions requiring protective action are discussed in Chapter 15 and Technical Specifications.

7.3.1.2.5 Abnormal Events

The malfunctions, accidents, or other unusual events which could physically damage Protection System components or could cause environmental changes are as follows:

1. Earthquakes (see Sections 3.7N and 3.7B).

2. Fire (see Section 9.5.1).

3. Deleted.

4. Missiles (see Section 3.5).

5. Flood (see Section 3.4).

6. Wind and tornadoes (see Section 3.3)

7. Loss of Coolant Accidents (see Section 6.2)

8. Steam line breaks (see Section 6.2)

9. Loss of ventilation (see Section 9.4)

7.3.1.2.6 Minimum Performance Requirements

Minimum performance requirements are as follows:

1. System response times

   The ESFAS response time is defined as the interval required for the engineered safety features sequence to be initiated subsequent to the point in time that the appropriate variable(s) exceed setpoints. The response time includes sensor/process (analog) and logic (digital) delay plus, the time delay associated with tripping open the reactor trip breakers and control and latching mechanisms, although the engineered safety features actuation signal occurs before or simultaneously with engineered safety features sequence initiation (see Figure 7.2- 1, Sheet 8). Therefore, the response times to initiating engineered safety features presented herein are conservative. The values listed herein are maximum allowable times consistent with the safety analyses and are systematically verified during plant preoperational startup tests. These maximum delay times thus include all compensation and therefore require that any such network be aligned and operating during verification.

   The ESFAS is always capable of having response time tests performed using the same methods as those tests performed during the preoperational test program or following significant component changes. Refer to Section 7.1.2.11 for a discussion of periodic response time verification capabilities.

   Maximum allowable time delays in generating the Engineered Safeguards actuation signal are justified through the accident analyses and specified in the Technical Requirements Manual.

2. System accuracies

   Accuracies required for generating the required actuation signals for loss of coolant protection are:

a.	Pressurizer pressure	±2.25 percent of span

   Accuracies required in generating the required actuation signals for a steam line break protection are given:

a.	Steam line pressure	±2.25 percent of span
b.	Steam line pressure rate	±5 psi/sec
c.	Containment pressure signal	±1.75 percent of full scale

3. Ranges of sensed variables to be accommodated until conclusion of protective action is assured.

Ranges required in generating the required actuation signals for loss of coolant protection are given:

a.	Pressurizer pressure	1700 to 2500 psig
b.	Containment pressure	0 to 60 psig

Ranges required in generating the required actuation signals for steam line break protection are given:

a.	Steam line pressure	0 to 1300 psig

7.3.1.3 Final System Drawings

The schematic diagrams for the systems discussed in this section are listed in Section 1.7 and are submitted in support of this application.

Figure 7.1-3 depicts the location layout of Engineered Safety Features instrumentation for systems discussed in this section.

7.3.2 ANALYSIS

7.3.2.1 Failure Mode and Effects Analyses

Failure mode and effects analyses have been performed on Engineered Safety Features Systems (ESFS) equipment within the scope of Westinghouse. The results verify that these systems meet protection single failure criteria as required by IEEE Standard 279-1971.

The failure mode and effects analysis (FMEA) which was performed on Engineered Safety Features (ESF) equipment within the scope of Westinghouse was for a typical Westinghouse ESF actuation system (ESFAS). See Reference [5].

Appendix B and C of revision 1 to WCAP-8584 provides interface criteria for the failure modes and effects analysis. This criteria is included in the Westinghouse generic interface criteria which has been provided to CPNPP and has been incorporated into the BOP design.

The analysis has application to the Comanche Peak Nuclear Power Plant (CPNPP) ESFAS as well as generic application to all Westinghouse ESFAS of the CPNPP vintage for the following reasons:

1. The CPNPP ESFAS equipment is designed to equivalent safety design criteria.

2. The actuation of the CPNPP Engineered Safety Features Systems is functionally the same as the systems studies in this analyses.

3. The FMEA was of an ESFAS that employed the Solid State Protection System (SSPS) and the 7300 series Process Control System (PCS).

4. The FMEA has been performed down to the replaceable component level, such as transmitters, relays, modules, and cards which are the same family of components as those applied to the CPNPP.

The conclusion is that the analysis (1) qualitatively demonstrates the reliability of the CPNPP ESFAS to perform is intended function and (2) shows that the ESFAS does comply with the single failure criterion, because no single failure was found which could prevent the ESFAS from generating the proper actuation signal on demand for an engineered safety feature. Random single failures are either in a safe direction or a redundant channel or train ensures the necessary actuation capability.

The basis of an FMEA is principally that single failures are detectable, identifiable, and random. They are not systematic (common mode). The systematic failure considerations applied to equipment hardware, as well as actuation functions, are addressed elsewhere in the FSAR, such as:

1. Seismic qualification of Seismic Category I instrumentation and electrical equipment (Section 3.10). This conforms to Section 4.7.4.2 of IEEE 279-1971.

2. Environmental design of mechanical and electrical equipment (Section 3.11). This conforms to Section 4.7.4.2 of IEEE 279-1971.

3. The Nuclear Instrumentation System, the Solid State Protection System, and the 7300 Series Process Control System noise tests (See Section 7.1.2.2.1 and Reference 2 in Section 7.2).

4. Manual initiation of protective actions (See Section 7.3.2.2.7).

For the engineered safety features and support equipment, failure mode and effects analyses are as follows:

1. Emergency Core Cooling System, Section 6.3 and Table 6.3-10.

2. Containment Spray System, Section 6.2.2 and Table 6.2.5-5.

3. Containment Isolation System, Section 6.2.4 - Failure mode and effects analysis is not applicable; Refer to Table 6.2.4-1 for Valve Arrangement and General Design Criteria applicability.

4. Combustible Gas Control Systems, Section 6.2.5 and Table 6.2.5- 5.

5. Control Room Air-Conditioning System, Section 9.4 and Table 9.4-8.

6. Auxiliary Feedwater System, Section 10.4.9, Table 10.4-9.

7. ESF Filter System, Section 6.5, Tables 9.4-8 and 9.4-9.

8. Component Cooling Water System, Section 9.2.2 and Table 9.2-5.

9. Service Water System, Section 9.2.1 and Table 9.2-1.

10. On Site Power Supply System, Sections 8.3.1, 9.5.4, 9.5.5 and Tables 8.3-3, 9.5-11, 9.5-12.

11. ESF Ventilation System, Section 9.4.5 discusses failure modes.

12. Safety Chilled Water, Section 9.4F discusses system redundancy and single failure.

13. Service Water Intake Structure Ventilation Section 9.4B discusses system redundancy and single failure.

7.3.2.2 Compliance With Standards and Design Criteria

Discussion of GDC are provided in various sections of Chapter 7 where a particular GDC is applicable. Applicable GDC include Criteria 13, 20, 21, 22, 23, 24, 25, 35, 37, 40, 43, and 46. Compliance with certain IEEE Standards is presented in Sections 7.1.2.7, 7.1.2.9, 7.1.2.10, and 7.1.2.11. Compliance with Regulatory Guide 1.22 is discussed in Section 7.1.2.5. The discussion given below shows that the ESFAS complies with IEEE Standard 279-1971, Reference [4]. For the list of references to the discussions of conformance to applicable criteria, see Table 7.1-1.

7.3.2.2.1 Single Failure Criteria

The discussion presented in Section 7.2.2.2.3 is applicable to the ESFAS, with the following exception.

In the engineered safety features, a loss of instrument power will call for actuation of engineered safety features equipment controlled by the specific bistable that lost power (containment spray and RWST Low-Low excepted). The actuated equipment must have power to comply. The power supply for the protection systems is discussed in Section 7.6 and in Chapter 8. For containment spray, the final bistables are energized to trip to avoid spurious actuation. In addition, manual containment spray requires a simultaneous actuation of two manual controls. This is considered acceptable because spray actuation on hi-3 containment pressure signal provides automatic initiation of the system via protection channels meeting the criteria in Reference [3]. Moreover, two sets (two switches per set) of containment spray manual initiation switches are provided to meet the requirements of IEEE Standard 279-1971. Also, it is possible for all engineered safety features equipment (valves, pumps, etc.) to be individually manually actuated from the control board. Hence, a third mode of containment spray initiation is available. The design meets the requirements of Criteria 21 and 23 of the 1971 GDC.

7.3.2.2.2 Equipment Qualification

Equipment qualifications are discussed in Sections 3.10B, 3.10N, 3.11B and 3.11N.

7.3.2.2.3 Channel Independence

The discussion presented in Section 7.2.2.2.3 is applicable. The engineered safety features slave relay outputs from the solid state logic protection cabinets are redundant, and the actuations associated with each train are energized up to and including the final actuators by the separate alternating current (AC) power supplies which power the logic trains.

7.3.2.2.4 Control and Protection System Interaction

The discussions presented in Section 7.2.2.2.3 are applicable.

7.3.2.2.5 Capability for Sensor Checks and Equipment Test and Calibration

The discussions of system testability in Section 7.2.2.2.3 are applicable to the sensors, analog circuitry, and logic trains of the ESFAS.

The following discussions cover those areas in which the testing provisions differ from those for the Reactor Trip System.

Testing of Engineered Safety Features Systems

The engineered safety features systems are tested to provide assurance that the systems will operate as designed and will be available to function properly in the unlikely event of an accident. The testing program meets the requirements of Criteria 21, 37, 40 and 43 of the 1971 GDC and Regulatory Guide 1.22 as discussed in Section 7.1.2.5. The tests described in Section 7.3.2.2.3 and further discussed in Section 6.3.4 meet the requirements on testing of the Emergency Core Cooling System as stated in GDC 37 except for the operation of those components that will cause an actual safety injection. The test, as described, demonstrates the performance of the full operational sequence that brings the system into operation, the transfer between normal and emergency power sources and the operation of associated cooling water systems. The safety injection and residual heat removal pumps are started and operated and their performance verified in a separate test discussed in Section 6.3.4. When the pump tests are considered in conjunction with the Emergency Core Cooling System test, the requirements of GDC 37 on testing of the Emergency Core Cooling System are met as closely as possible without causing an actual safety injection.

Testing as described in Sections 6.3.4, 7.2.2.2.3 and 7.3.2.2.3 provides complete periodic testability during reactor operation of all logic and components associated with the Emergency Core Cooling System. This design meets the requirements of Regulatory Guide 1.22 as discussed in the above sections. The program is as follows:

1. Prior to initial plant operations, Engineered Safety Features System tests will be conducted.

2. Subsequent to initial startup, Engineered Safety Features System tests will be conducted during each regularly scheduled refueling outage.

3. During on-line operation of the reactor, all of the engineered safety features analog and logic circuitry will be fully tested. In addition, essentially all of the engineered safety features final actuators will be fully tested. The remaining few final actuators whose operation is not compatible with continued on-line plant operation will be checked by means of continuity testing.

4. During normal operation, the operability of testable final actuation devices of the engineered safety features systems will be tested by manual initiation from the Control Room.

Performance Test Acceptability Standard for the “S” (Safety Injection Signal) and for the “P” (the Automatic Demand Signal for Containment Spray Actuation) Actuation Signals Generation

During reactor operation the basis for ESFAS acceptability will be the successful completion of the overlapping tests performed on the initiating system and the ESFAS, see Figure 7.3-2. Checks of process indications verify operability of the sensors. Analog checks and tests verify the operability of the analog circuitry from the input of these circuits through the channel bistable output. Channel calibrations verify the operability of the channel bistable output through to and including the logic input relays except for the input relays associated with the containment spray function which are tested during the solid state logic testing. Solid state logic testing also checks the digital signal path from the logic input relay contacts through the logic matrices and master relays and perform continuity tests on the coils of the output slave relays; final actuator testing operates the output slave relays and verifies operability of those devices which require safeguards actuation and which can be tested without causing plant upset. A continuity check is performed on the actuation circuitry of the untestable devices. Operation of the Final devices is confirmed by control board indication or visual observation that the appropriate pump breakers close and automatic valves have completed their travel.

The basis for acceptability for the engineered safety features interlocks will be control board indication of proper receipt of the signal upon introducing the required input at the appropriate setpoint.

Frequency of Performance of Engineered Safety Features Actuation Tests

During reactor operation, complete system testing (excluding sensors or those devices whose operation would cause plant upset) is performed periodically as specified in the Technical Specifications. Testing, including the sensors, is also performed during scheduled plant shutdown for refueling.

Engineered Safety Features Actuation Test Description

The following sections describe the testing circuitry and procedures for the on-line portion of the testing program. The guidelines used in developing the circuitry and procedures are:

1. The test procedures must not involve the potential for damage to any plant equipment.

2. The test procedures must minimize the potential for accidental tripping.

3. The provisions for on-line testing must minimize complication of engineered safety features actuation circuits so that their reliability is not degraded.

Description of Initiation Circuitry

Several systems comprise the total Engineered Safety Features System, the majority of which may be initiated by different process conditions and be reset independently of each other.

The remaining functions (listed in Section 7.3.1.1.1) are initiated by a common signal (safety injection) which in turn may be generated by different process conditions.

In addition, operation of all other vital auxiliary support systems, such as auxiliary feedwater, component cooling and service water, is initiated by the safety injection signal.

Each function is actuated by a logic circuit which is duplicated for each of the two redundant trains of engineered safety features initiation circuits.

The output of each of the initiation circuits consists of a master relay which drives slave relays for contact multiplication as required. The logic, master, and slave relays are mounted in the solid state logic protection cabinets designated train A, and train B, respectively, for the redundant counterparts. The master and slave relay circuits operate various pump and fan circuit breakers or starters, motor operated valve contactors, solenoid operated valves, emergency generator starting, etc.

Analog Testing

Analog testing is identical to that used for reactor trip circuitry and is described in Section 7.2.2.2.3.

Solid State Logic Testing

Except for containment spray channels, solid state logic testing is the same as that discussed in Section 7.2.2.2.3. During logic testing of one train, the other train can initiate the required engineered safety features function. For additional details, refer to Reference [2].

Actuator Testing

At this point, testing of the initiation circuits through operation of the master relay and its contacts to the coils of the slave relays has been accomplished. The ESFAS logic slave relays in the Solid State Protection System output cabinets are subjected to coil continuity tests by the output relay tester in the Solid State Protection System cabinets. Slave relays (K601, K602, etc.) do not operate because of reduced voltage applied to their coils by the mode selector switch (TEST/OPERATE). A multiple position master relay selector switch chooses different master relays and corresponding slave relays to which the coil continuity is applied. The master relay selector switch is returned to “OFF” before the mode selector switch is placed back in the “OPERATE” mode. However, failure to do so will not result in defeat of the protective function. The ESFAS slave relays are activated during testing by the on-line test cabinet, so that overlap testing is maintained.

The ESFAS final actuation device or actuated equipment testing shall be performed from the engineered safeguards test cabinets. These cabinets are located near the Solid State Logic Protection System equipment. There is one set of test cabinets provided for each of the two protection trains A and B. Each set of cabinets contains individual test switches necessary to actuate the slave relays. To prevent accidental actuation, test switches are of the type that must be rotated and then depressed to operate the slave relays. Assignments of contacts of the slave relays for actuation of various final devices or actuators has been made such that groups of devices or actuated equipment, can be operated individually during plant operation without causing plant upset or equipment damage. In the unlikely event that a safety injection signal is initiated during the test of the final device that is actuated by this test, the device will already be in its safeguards position. Redundant devices in the opposite train will be functional for those components that will be made inoperable due to establishing plant conditions to support testing.

During this last procedure, close communication between the main Control Room operator and the operator at the test panel is required. Prior to the energizing of a slave relay, the operator in the main Control Room assures or establishes plant conditions that will permit operation of the equipment to be actuated by the relay. Appropriate LCOs will be entered for those devices rendered inoperable due to test set-up requirements. After the tester has energized the slave relay, the main Control Room operator observes that all equipment has operated as indicated by appropriate indicating lamps, monitor lamps and annunciators on the control board and records all operations. For the test of slave relays associated with the turbine trip from Reactor Trip or Engineered Safety Features System actuation, the Operator will observe on the OM computer workstation screen that all relay-activated equipment has operated as indicated. After observing all the results, the Operator then resets all devices and prepares for operation of the next slave relay actuated equipment.

The following methodology will be used for those final actuation device circuits that cannot be operated by an individual slave relay or actuation of which will cause plant upset/equipment damage and for which no additional block testing circuitry is provided. The end device will be declared inoperable and then disabled from operating by removing fuses/opening breakers, etc. The slave relay will be energized as described above. Proper slave relay state change will then be verified through local control circuit continuity measurements. Restoration of the slave will be as above followed by restoration of equipment to the status required per Technical Specifications.

Automatic actuation circuitry of all engineered safety features devices actuated by ESFAS initiation circuits, with the exceptions noted in Section 7.1.2.5 under a discussion of Regulatory Guide 1.22, are tested by means of the procedures outlined above.

Actuator Blocking and Continuity Test Circuits

This section describes methodology used for those final actuation devices that cannot be designed to be actuated during plant operation (discussed in Section 7.1.2.5) and that have been assigned to slave relays for which additional test circuitry has been provided to individually block actuation of a final device upon operation of the associated slave relay during testing. Operation of these slave relays, including contact operations, and continuity of the electrical circuits associated with the final devices control are checked in lieu of actual operation. The circuits provide for monitoring of the slave relay contacts, the devices control circuit cabling, control voltage and the devices actuation solenoids. Interlocking prevents blocking the output from more than one output relay in a protection train at a time. Interlocking between trains is also provided to prevent continuity testing simultaneously in both trains; therefore, the redundant device associated with the protection train not under test will be available in the event the protection action is required. If an accident occurs during testing, the automatic actuation circuitry will override testing as noted above. An exception to this is that if the accident occurs while testing a slave relay whose output must be blocked, the final actuation devices associated with this slave relay will not be overridden; however, the redundant devices in the other train would be operational and would perform the required safety function. Actuation devices to be blocked are identified in Section 7.1.2.5.

The continuity test/indication circuits for these components with blocking relay circuits are verified by proving lights on the safeguards test racks, or by indication on OM computer workstations in the control room.

The typical schemes for blocking operation of selected protection function actuator circuits are shown in Figure 7.3-3 as details A and B. The schemes operate as explained below and are duplicated for each safeguards train. The method for blocking operation of turbine trip (from Reactor Trip or Engineered Safety Features System actuation) is an exception to these schemes. This method is also explained below.

Detail A shows the circuit for contact closure for protection function actuation. Under normal plant operation, and equipment not under test, the test lamps “DS*” for the various circuits will be energized. Typical circuit path will be through the normally closed test relay contact “K8*” and through test lamp connections 1 to 3. Coil “X1” will be capable of being energized for protection function actuation upon closure of solid state logic output relay contacts “K*”. Coil “X1” is typical for a breaker closing auxiliary coil, motor starter master coil, coil of a solenoid valve, auxiliary relay, etc. When the contacts “K8*” are opened to block energizing of coil “X1”, the white lamp is de-energized, and the slave relay “K*” may be energized to perform continuity testing. To verify operability of the blocking relay in both blocking and restoring normal service, open the blocking relay contact in series with lamp connections - the test lamp should be de-energized; close the blocking relay contact in series with the lamp connections - the test lamp should now be energized, which verifies that the circuit is now in its normal, i.e., operable condition.

Detail B shows the circuit for contact opening for protection function actuation. Under normal plant operation, and equipment not under test, the white test lamps “DS*” for the various circuits will be energized, and green test lamp “DS*” will be de-energized. Typical circuit path for white lamp “DS*” will be through the normally closed solid state logic output relay contact “K*” and through test lamp connections 1 to 3. Coils “Y1” and “Y2” will be capable of being de- energized for protection function actuation upon opening of solid state logic output relay contacts “K*.” Coil “Y2” is typical for a solenoid valve coil, auxiliary relay, etc. When the contacts “K8*” are closed to block de-energizing of coils “Y1” and “Y2”, the green test lamp is energized and the slave relay “K*” may be energized to verify operation (opening of its contacts). To verify operability of the blocking relay in both blocking and restoring normal service, close the blocking relay contact to the green lamp - the green test lamp should now be energized also; open this blocking relay contact - the green test lamp should be de- energized, which verifies that the circuit is now in its normal, i.e., operable position.

Time Required for Testing

It is estimated that analog testing can be performed at a rate of several channels per hour. Logic testing of both trains A and B can be performed in less than 30 minutes. Testing of actuated components (including those which can only be partially tested) will be a function of Control Room operator availability. It is expected to require several shifts to accomplish these tests. During this procedure automatic actuation circuitry will override testing, except for those few devices associated with a single slave relay whose outputs must be blocked (and then only while blocked) and for those devices rendered inoperable due to test set-up requirements. It is anticipated that testing associated with one of these slave relays could take several minutes. During this time the redundant devices in the other trains would be functional.

Summary of On-Line Testing Capabilities

The procedures described provide capability for checking completely from the process signal to the logic cabinets and from there to the individual pump and fan circuit breakers or starters, valve contactors, pilot solenoid valves, etc., including all field cabling actually used in the circuitry

called upon to operate for an accident condition. For those few devices whose operation could adversely affect plant or equipment operation, the same procedure provides for checking from the process signal to the logic rack. Actuation of the final actuation device circuitry is checked through continuity testing.

The procedures require testing at various locations.

1. Analog testing and verification of bistable setpoint are accomplished at process analog racks. Verification of bistable relay operation is done at the main Control Room status lights.

2. Logic testing through operation of the master relays and low voltage application to slave relays is done at the logic rack test panel.

3. Testing of pumps, fans and valves is done at a test panel located in the vicinity of the logic racks in combination with the Control Room operator.

4. Continuity testing for those circuits with additional block testing circuits is done at the same test panel mentioned in item 3 above.

5. Control circuit continuity testing of contacts associated with those untestable slave relays without additional block testing circuitry will be performed locally.

For the case of turbine trip (from Reactor Trip or Engineered Safety Features System actuation), the trip and blocking relay contacts input directly to the Turbine Generator Digital Protection System. Test lamps (as described for Details A and B above) do not exist for these circuits. During normal plant operation with no equipment test in progress, trip and block indications are absent on the Turbine Protection System operator workstation. When the blocking relay is actuated, the block is indicated on the operator workstation, and the turbine trip output signal is blocked in the system software. When the trip relay is actuated, the trip is indicated on the operator workstation, confirming operation of the trip relay contacts. The trip and blocking relays are then restored. The associated operator workstation indications clear to indicate that the relays have been satisfactorily returned to the normal operating condition. As long as the block signal is present, annunciation is provided on the operator workstation to ensure that the block is removed after testing is complete.

Testing During Shutdown

Emergency Core Cooling System tests will be performed periodically in accordance with the Technical Specifications with the Reactor Coolant System isolated from the Emergency Core Cooling System by closing the appropriate valves. A test safety injection signal will then be applied to initiate operation of active components (pumps and valves) of the Emergency Core Cooling System. This is in compliance with Criterion 37 of the 1971 GDC.

Containment Spray System tests will be performed at each major fuel reloading. The tests will be performed with the isolation valves in the spray supply lines at the containment and spray additive tank blocked closed and are initiated by tripping the normal actuation instrumentation.

Periodic Maintenance Inspections

The maintenance procedures which follow will be accomplished per applicable plant procedures. The frequency will depend on the operating conditions and requirements of the reactor power plant. If any degradation of equipment operation is noted, either mechanically or electrically, remedial action is taken to repair, replace, or readjust the equipment. Optimum operating performance must be achieved at all times.

Maintenance procedures include the following:

1. Check cleanliness of all exterior and interior surfaces.

2. Check all fuses for corrosion.

3. Inspect for loose or broken control knobs and burned out indicator lamps.

4. Inspect for moisture and condition of cables and wiring.

5. Mechanically check all connectors and terminal boards for looseness, poor connection, or corrosion.

6. Inspect the components of each assembly for signs of overheating or component deterioration.

7. Perform complete system operating check.

The balance of the requirements listed in Reference [4] (Sections 4.11 through 4.22) are discussed in Section 7.2.2.2.3. Section 4.20 of Reference [4] receives special attention in Section 7.5.

7.3.2.2.6 Manual Resets and Blocking Features

Manual reset and block functions for the ESFAS are shown on Figure 7.2-1, Sheet 8. The purpose for each is as follows:

1. Safety injection system level reset is required after an accident to terminate safety injection and allow switchover to recirculation in the case of operator actions following a LOCA, to permit the operator to take over manual control of a tripped reactor, and, to complete the shutdown process following a transient or accident that initiates safety injection, as well as to recover from a false signal.

2. Containment spray actuation reset is needed to allow for recovery from all accidents that initiate containment spray, as well as to recover from a false signal.

3. Containment isolation phase A reset is needed to allow for defeat of containment isolation phase A during recovery from an accident, as well as to recover from a false signal.

4. Containment isolation phase B reset is needed to allow for defeat of containment isolation phase B during recovery from an accident that initiated phase B isolation, as well as to recover from a false signal.

5. Containment ventilation isolation reset is needed to allow for defeat of containment ventilation isolation during recovery from an accident that initiated it. In recovering from a false signal, the false signal is expected to be cleared prior to reset.

6. Control Room intake duct isolation and emergency filter actuation reset is needed to permit the operator to bring the Control Room air conditioning system into its normal operational mode, as well as to recover from a false signal. The functional logic for this reset function is shown in instrumentation and control diagrams listed under “Control Room Air Conditioning” in Table 1.7-1.

7. Main steam line isolation reset is a retentive memory circuit only, and does not include the maintained-actuation-signal-block function. This manual reset will allow opening the steam line stop valves following a transient should the transient automatically generate main steam line isolation actuation after the automatic actuation signal has been eliminated for reasons that include the use of the steam dump through the non-faulted steam generator if offsite power is available.

The manual reset feature associated with containment spray actuation, and the manual block features associated with pressurizer and steam line safety injection signals, are discussed in further detail in the following paragraphs.

The manual reset feature associated with containment spray actuation is provided in the standard design of the Westinghouse Solid State Protection System design for two basic purposes. First, the feature permits the operator to start an interruption procedure of automatic containment spray in event of false initiation of an actuate signal. Second, although spray system performance is automatic, the reset feature enables the operator to start a manual takeover of the system to handle unexpected events which can be better dealt with by operator appraisal of changing conditions following an accident.

It is most important to note that manual control of the spray system does not occur, once actuation has begun, by just resetting the associated logic devices alone. Components will seal in (latch) so that removal of the actuate signal, in itself, will neither cancel or prevent completion of protective action or provide the operator with manual override of the automatic system by this single action. In order to take complete control of the system to interrupt its automatic performance, the operator must deliberately unlatch relays which have “sealed in” the initial actuate signals in the associated motor control center, in addition to tripping the pump motor circuit breakers, if stopping the pumps is desirable or necessary.

The manual reset feature associated with containment spray, therefore, does not perform a bypass function. It is merely the first of several manual operations required to take control from the automatic system or interrupt its completion should such an action be considered necessary.

In event that the operator anticipates system actuation and erroneously concludes that it is undesirable or unnecessary and imposes a standing reset condition in one train (by operating and holding the corresponding reset switch at the time the initiate signal is transmitted) the other train will automatically carry the protective action to completion. In the event that the reset condition is imposed simultaneously in both trains at the time the initiate signals are generated, the automatic sequential completion of system action is interrupted and control has been taken by the operator. Manual takeover will be maintained, even though the reset switches are

released, if the original initiate signal exists. Should the initiate signal then clear and return again, automatic system actuation will repeat.

Note also that any time delays imposed on the system action are to be applied after the initiating signals are latched. Delay of actuate signals for fluid systems line-up, load sequencing, etc., do not provide the operator time to interrupt automatic completion, with manual reset alone, as would be the case if time delay was imposed prior to sealing of the initial actuate signal.

The manual block features associated with pressurizer and steam line safety injection signals provide the operator with the means to block initiation of safety injection during plant startup and shutdown.

Safety injection actuation on low pressurizer pressure and low steam line pressure may be manually blocked when NSSS pressure falls below P-11. If a steam line rupture occurs while both of these safety injection actuation signals are blocked, steam line isolation will occur on high negative steam pressure rate.

Prior to blocking safety injection, the shutdown margin at hot standby, as listed in Technical Specifications, will be increased by the amount necessary to makeup for the shutdown margin to be lost via cooldown and to maintain the Technical Specification shutdown margin for the applicable mode of operation. Thus, before cooldown is initiated, the boron concentration will be at least as great as the maximum required boron concentration during cooldown. This increased margin ensures that the steam line rupture return to power from hot zero power (see Section 6.3.3.3) is higher than the case where safety injection actuation is manually blocked on low steam line pressure and low pressurizer pressure. Therefore, no further protection is required.

During a plant cooldown, the operator is instructed to manually block the automatic safety injection signals when pressure falls below P-11. This action disarms the safety injection signals from the pressurizer pressure transmitters along with the steam line pressure transmitters. The other safety injection signal, containment high pressure, is armed and will actuate safety injection if the setpoint is exceeded. Manual safety injection actuation is also available.

During the post-LOCA recovery, or recovery from any event where safety injection has been actuated, the reactor operator is instructed to reset Safety Injection and, as conditions allow, secure various ECCS components. If plant conditions degrade such that ECCS actuation is again required, the reactor operator is instructed to individually restart any required ECCS components.

These block features meet the requirements of Section 4.12 of IEEE Standard 279-1971 in that automatic removal of the block occurs when plant conditions require the protection system to be functional.

7.3.2.2.7 Manual Initiation of Protective Actions (Regulatory Guide 1.62)

There are four individual main steam stop valve momentary control switches (one per loop) mounted on the control board. Each switch when actuated will isolate one of the main steam lines. In addition, there will be two system level switches. Each switch will actuate all four main steam line isolation valves of the system level. Manual initiation of switchover to recirculation is in compliance with Section 4.17 of IEEE Standard 279-1971 with the following comment.

Manual initiation of either one of two redundant safety injection actuation main control board mounted switches provides for actuation of the components required for reactor protection and mitigation of adverse consequences of the postulated accident, including delayed actuation of sequenced started emergency electrical loads as well as components providing switchover from the safety injection mode to the cold leg recirculation mode following a loss of primary coolant accident. Therefore, once safety injection is initiated, those components of the Emergency Core Cooling System (see Section 6.3) which are automatically realigned as part of the semiautomatic switchover go to completion on low-low refueling water storage tank (RWST) water level without any manual action. Manual operation of other components or manual verification of proper position as part of emergency procedures is not precluded nor otherwise in conflict with the above described compliance to Section 4.17 of IEEE Standard 279- 1971 of the semiautomatic switchover circuits.

No exception to the requirements of IEEE Standard 279-1971 has been taken in the manual initiation circuit of safety injection. Although Section 4.17 of IEEE Standard 279-1971 requires that a single failure within common portions of the protective system shall not defeat the protective action by manual or automatic means, the standard does not specifically preclude the sharing of initiated circuitry logic between automatic and manual functions. It is true that the manual safety injection initiation functions associated with one actuation train (e.g., train A) shares portions of the automatic initiation circuitry logic of the same logic train; however, a single failure in shared functions does not defeat the protective action of the redundant actuation train (e.g., train B). A single failure in shared functions does not defeat the protective action of the safety function. It is further noted that the sharing of the logic by manual and automatic initiation is consistent with the system level action requirements of the IEEE Standard 279-1971, Section 4.17, and the minimization of complexity.

Manual actuation of main steam line isolation (all valves), containment isolation (Phase A), and containment spray actuation conforms to the same criteria herein described for the manual safety injection manual actuation functions.

7.3.2.2.8 Component Control Switches

The control switches for ESF final actuators, e.g., pumps, valves and dampers which receive an ESF actuation signal are either the spring-return-to-automatic type or are maintained in one manual (i.e., non-automatic) position. The safe position of the ESF final actuator will be obtained in response to an ESF actuation signal or the maintained position of the control switch will place the actuator in the safe position required by the ESF signal. This design assures the completion of the protective function once it has been initiated, regardless of the position of the actuator control switch.

When operating conditions necessitate, the operator can manually override the automatic operation of individual components. The manual overrides are accomplished in the following manner:

1. Valves and Dampers - The control switch must be held by the operator in the alternate position for the duration of the period that the alternate action is required. The automatic action is restored as soon as the operator releases the control switch.

2. Pumps - For those pumps that receive an auto start signal from the ESF sequencer, the operator can stop the pump by holding the control switch in the stop position. After the

sequencer has cycled, the pump will not restart when the operator releases the control switch. This override will be continuously indicated in the control room and both the override and the indication will be automatically removed whenever permissive conditions for the bypass are not met.

The alternate operating mode is provided with permissives or operator lockouts that prevents the operator from intervening in the automatic operation of the final actuator when the ESF sequencer is in operation.

This manual override meets the intent of IEEE Std 279 requirements for operating bypasses. The channel is not removed from service during the period that the operator is manually operating the component and the operator has status indicating lamps to inform him of the status of the final actuator.

7.3.2.3 Further Considerations

In addition to the considerations given above, a loss of instrument air or loss of component cooling water to vital equipment has been considered. Neither the loss of instrument air nor the loss of cooling water (assuming no other accident conditions) can cause safety limits as given in the Technical Specifications to be exceeded. Likewise, loss of either one of the two will not adversely affect the core or the Reactor Coolant System nor will it prevent an orderly shutdown if this is necessary. Furthermore, all pneumatically operated valves and controls will assume a preferred operating position upon loss of instrument air or safety related air accumulators are provided (see Section 9.3.1). It is also noted that, for conservatism during the accident analysis (see Chapter 15), credit is not taken for the instrument air systems nor for any control system benefit.

The design does not provide any circuitry which will directly trip the reactor coolant pumps on a loss of component cooling water. Normally, indication in the Control Room is provided whenever component cooling water is lost. The reactor coolant pumps can run about 10 minutes after a loss of component cooling water. This provides adequate time for the operator to correct the problem or trip the plant if necessary.

A loss of Component Cooling Water (CCW) flow to the Reactor Coolant Pumps (RCP) is alarmed in the Control Room. The alarms are not expected to be operable during or after a LOCA or SSE condition. The alarm system that is actuated on CCW loss of flow to the RCP consists of:

1. Flow detection bistables or switches.

2. Annunciator electronics, lamp cabinets, audible horns.

Although the alarm system is not designed to remain operational with single failure in either “a” or “b” above, item “b” does contain certain features for increased reliability as follows:

1. Redundant input power sources, 125 volts DC and 120V AC with auto transfer feature.

2. Display windows in Lamp Cabinets with dual lamps.

3. Multiple audible horns

Furthermore, the alarm contacts which are normally closed, open to alarm. This provides a self monitoring feature which detects an open circuit condition, such as caused by an open wire.

The alarm system, as described above is classified as non safety related, and is not qualified to IEEE-323-1974 and 344-1975.

The alarms for loss of CCW to the RCP upper bearing lube-oil cooler or to the lower bearing lube-oil cooler are originated by in-line rotameters. The time delay between the loss of CCW flow and the initiation of the alarm, is between 4 to 7 seconds time lag is due mainly to the time it takes the float to change positions. The time lag for the remaining instrument loop is in the order of milli-secs. The alarms for loss of CCW to the RCP Motor Air Cooler or to the RCP thermal barrier are originated by differential pressure transmitter, square-root-extractor and bistable. The time delay is, in this case, less than a second and is the combined time of the transmitter to sense the change of flow and the bistable relay to operate. The time lag for the remaining instruments of the loop is in the order of the milli-seconds.

7.3.2.4 Summary

The effectiveness of the ESFAS is evaluated in Chapter 15, based on the ability of the system to contain the effects of Condition III and IV events, including loss of coolant and steam break accidents. The ESFAS parameters are based upon the component performance specifications which are given by the manufacturer or verified by test for each component. Appropriate factors to account for uncertainties in the data are factored into the constants characterizing the system.

The ESFAS must detect Condition III and IV events and generate signals which actuate the engineered safety features. The system must sense the accident condition and generate the signal actuating the protection function reliably and within a time determined by and consistent with the accident analyses in Chapter 15.

Much longer times are associated with the actuation of the mechanical and fluid system equipment associated with engineered safety features. This includes the time required for switching, bringing pumps and other equipment to speed and the time required for them to take load.

Operating procedures require that the complete ESFAS normally be operable. However, redundancy of system components is such that the system operability assumed for the safety analyses can still be met with certain instrumentation channels out of service. Channels that are out of service are to be placed in the tripped mode or bypass mode in the case of containment spray.

7.3.2.4.1 Loss of Coolant Protection

By analysis of loss of coolant accident and in system tests it has been verified that except for very small coolant system breaks which can be protected against by the charging pumps followed by an orderly shutdown, the effects of various loss of coolant accidents are reliably detected by the low pressurizer pressure and water level signal; the Emergency Core Cooling System is actuated in time to prevent or limit core damage.

For large coolant system breaks the passive accumulators inject first, because of the rapid pressure drop. This protects the reactor during the unavoidable delay associated with actuating the active Emergency Core Cooling System phase.

High containment pressure also actuates the Emergency Core Cooling System. Therefore, emergency core cooling actuation can be brought about by sensing this other direct consequence of a primary system break; that is the ESFAS detects the leakage of the coolant into the containment. The generation time of the actuation signal of about 1.5 seconds, after detection of the consequences of the accident, is adequate.

Containment spray will provide additional emergency cooling of the containment and also limit fission product release upon sensing elevated containment pressure (hi-3) to mitigate the effects of a loss of coolant accident.

The delay time between detection of the accident condition and the generation of the actuation signal for these systems is assumed to be about 1.0 second, well within the capability of the Protection System equipment. However, this time is short compared to that required for startup of the fluid systems.

The analyses in Chapter 15 show that the diverse methods of detecting the accident condition and the time for generation of the signals by the protection systems are adequate to provide reliable and timely protection against the effects of loss of coolant.

7.3.2.4.2 Steam Line Break Protection

The Emergency Core Cooling System is also actuated in order to protect against a steam line break. About 2.0 seconds elapses between sensing low steam line pressure and generation of the actuation signal. Analysis of steam line break accidents assuming this delay for signal generation shows that the Emergency Core Cooling System is actuated for a steam line break in time to limit or prevent further core damage for steam line break cases. There is a reactor trip but the core reactivity is further reduced by the highly borated water injected by the Emergency Core Cooling System.

Additional protection against the effects of steam line break is provided by feedwater isolation which occurs upon actuation of the Emergency Core Cooling System. Feedwater line isolation is initiated in order to prevent excessive cooldown of the reactor vessel and thus protect the Reactor Coolant System boundary.

Additional protection against a steam line break accident is provided by closure of all steam line isolation valves in order to prevent uncontrolled blowdown of all steam generators. The generation of the Protection System signal (about 2.0 seconds) is again short compared to the time to trip the main steam isolation valves which are designed to close in less than 5 seconds after receipt of an isolation signal.

In addition to actuation of the engineered safety features, the effect of a steam line break accident may also generate a signal resulting in a reactor trip on overpower or following Emergency Core Cooling System actuation. However, the core reactivity is further reduced by the highly borated water injected by the Emergency Core Cooling System.

The analyses in Chapter 15 of the steam line break accidents and an evaluation of the Protection System instrumentation and channel design shows that the ESFAS is effective in preventing or mitigating the effects of a steam line break accident.

REFERENCES

1. Reid, J. B., "Process Instrumentation for Westinghouse Nuclear Steam Supply System (4 Loop Plant using WCID 7300 Series Process Instrumentation)," WCAP-7913, March 1973.

2. Katz, D. N., "Solid State Logic Protection System Description," WCAP-7488-L (Proprietary), March 1971 and WCAP-7672 (Non- Proprietary), May 1971.

3. Swogger, J. W., "Testing of Engineered Safety Features Actuation System," WCAP-7705, Revision 2, January 1976.

4. The Institute of Electrical and Electronics Engineers, Inc., "IEEE Standard: Criteria for Protection System for Nuclear Power Generating Stations," IEEE Standard 279-1971.

5. Eggleston, F. T., Rawlins, D. H., Petrow J. R., "Failure Mode and Effects Analysis (FMEA) of the Engineering Safeguard Features Actuation System," WCAP-8584, (Proprietary), Revision 1, February 1980 and WCAP-8760 (Non-Proprietary), Revision 1, February 1980.

6. Morgan, C. E., "Elimination of Periodic Protection Channel Response Time Tests," WCAP-14036-P-A, Revision 1, October 6, 1998.

TABLE 7.3-1
INSTRUMENTATION OPERATING CONDITIONS FOR ENGINEERED SAFETY FEATURES

No	Functional Unit	No. of Channels	No of Channels to Trip
1.	Safety injection		
	a. Manual	2	1
	b. High containment pressure (hi-1)	3	2
	c. Low compensated steam line pressure[(a)]	12 (3/steam line)	2 in any steam line
	d. Pressurizer low pressure[(a)]	4	2
2.	Containment spray		
	a. Manual[(b)]	4	2
	b. Containment pressure (hi-3)	4	2

a) Permissible bypass if reactor coolant pressure less than 2000 psig.

b) Manual actuation of containment spray is accomplished by actuating either of two sets (two switches per set). Both switches in a set must be actuated to obtain a manually initiated spray signal. The sets are wired to meet separation and single failure requirements of IEEE Standard 279-1971. Simultaneous operation of two switches is desirable to prevent inadvertent spray actuation.

TABLE 7.3-2
INSTRUMENT OPERATING CONDITIONS FOR ISOLATION FUNCTIONS

No.	Functional Unit	No. of Channels	No. of Channels to Trip
1.	Containment isolation		
	a. Automatic safety injection (Phase A)	See item 1 (b) through (d) of Table 7.3-1	
	b. Containment pressure (Phase B)	See item 2 (b) of Table 7.3-1	
	c. Manual		
	1) Phase A	2	1
	2) Phase B	See item 2 (a) of Table 7.3-1	
2.	Steam line isolation		
	a. Low steam line pressure[(a)]	12 (3/steam line)	2 in any one steam line
	b. Containment pressure (hi-2)	3	2
	c. High steam pressure rate	12 (3/steam line)	2 in any one
	d. Manual	2[(b)]	1[(b)]
3.	Feedwater line isolation		
	a. Safety injection	See item 1 of Table 7.3-1	
	b. Steam generator high-high level 2/3 on any steam generator	12 (3/Steam generator)	2 in any one steam generator
	c. Low T_{avg}(Average Temperature) Coincident with Reactor Trip	See Figure 7.2-1 Sh. 2, 5 & 13	See Figure 7.2-1 Sh. 2,5 & 13

a) Permissible by pass if reactor coolant pressure less than p-11 setpoint.

b) Additionally there is a switch for each loop that will actuate the mainsteam isolation valve for its respective loop.

TABLE 7.3-3
INTERLOCKS FOR ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

Designation	Input	Function Performed
P-4	Reactor trip	Actuates turbine trip
		Closes main and bypass feedwater valves on Low T_{avg} below setpoint.
		Prevents opening of main and bypass feedwater valves which were closed by injection or high-high steam generator water level
		Allows manual block of the automatic reactuation of safety injection
	Reactor not tripped	Defeats the block preventing automatic reactuation of safety injection
P-11	2/3 pressurizer pressure below setpoint	Allows manual block of safety injection actuation on low pressurizer pressure signal
		Allows manual block of safety injection actuation on low compensated steam line pressure signal
	2/3 pressurizer pressure above setpoint	Defeats manual block of safety injection actuation
P-12	2/4 Lo-Lo T_{avg} below setpoint	Blocks steam dump.
	3/4 Lo-Lo T_{avg} above setpoint	Defeats the manual bypass of steam dump block
P-14	2/3 steam generator water level above setpoint on any steam generator	Closes all feedwater control valves and isolation valves
		Trips all main feedwater pumps which closes the pumps discharge valves
		Actuates turbine trip

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 1 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
1-FCV-510	SG 1 Main Feedwater Flow Control Valve	A/B	Close	M1-2203-05
1-FCV-520	SG 2 Main Feedwater Flow Control Valve	A/B	Close	M1-2203-05
1-FCV-530	SG 3 Main Feedwater Flow Control Valve	A/B	Close	M1-2203-05
1-FCV-540	SG 4 Main Feedwater Flow Control Valve	A/B	Close	M1-2203-05
1-LV-2162	SG 1 Main Feedwater Bypass Control Valve	A/B	Close	M1-2203-05
1-LV-2163	SG 2 Main Feedwater Bypass Control Valve	A/B	Close	M1-2203-05
1-LV-2164	SG 3 Main Feedwater Bypass Control Valve	A/B	Close	M1-2203-05
1-LV-2165	SG 4 Main Feedwater Bypass Control Valve	A/B	Close	M1-2203-05
1-HV-2134	SG #1 Feedwater Isolation Valve	A/B	Close	M1-2203-04
1-HV-2135	SG #2 Feedwater Isolation Valve	A/B	Close	M1-2203-04
1-HV-2136	SG #3 Feedwater Isolation Valve	A/B	Close	M1-2203-04
1-HV-2137	SG #4 Feedwater Isolation Valve	A/B	Close	M1-2203-04
1-LCV-1003	RC Drain Tank Pressure & Level Control Valve	A	Close	M1-2264-02

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 2 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
1HV-2185	FWIV Bypass Valve	A/B	Close	M1-2203-07
1HV-2186	FWIV Bypass Valve	A/B	Close	M1-2203-07A
1HV-2187	FWIV Bypass Valve	A/B	Close	M1-2203-07A
1HV-2188	FWIV Bypass Valve	A/B	Close	M1-2203-07A
SJ14S031	Trip Fluid Solenoid Valve Channel 1	A/B	Trip	E1-0022-C
SJ14S032	Trip Fluid Solenoid Valve Channel 2	A/B	Trip	E1-0022-C
SJ14S033	Trip Fluid Solenoid Valve Channel 3	A/B	Trip	E1-0022-C
1-HV-3486	Service Air HDR to Containment Isolation Valve	B	Close	M1-2216-03
1-HV-3487	Instrument Air HDR to Containment Isolation Valve	B	Close	M1-2216-03
1-HV-4075B	Fire Prot. Wtr. to Standpipes Isolation Valve	B	Close	M1-2225-01B
1-HV-4075C	Fire Prot. Wtr. to Standpipes Isolation Valve	A	Close	M1-2225-01B
1-HV-4165	Pressurizer Stm. Space - Prim. Samp. Sys. Valve	A	Close	M1-2228-01
1-HV-4166	Pressurizer Stm. Space to Prim. Samp. Sys. Control Valve	A	Close	M1-2228-01

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 3 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
1-HV-4167	Pressurizer Liq. Space to Prim. Samp. Sys Control Valve.	B	Close	M1-2228-01A
1-HV-4168	RC Loop 1 HOT LEG to Prim. Samp. Sys. Control Valve	A	Close	M1-2228-03
1-HV-4169	RC Loop 4 HOT LEG to Prim. Samp. Sys. Control Valve	A	Close	M1-2228-03
1-HV-4170	RC Loops 1 & 4 HOT LEG to Prim. Samp. Sys Control Valve.	B	Close	M1-2228-04
1-HV-4171	Accumulator 1 Liq. Space to Prim. Samp. Sys. Control Valve	A	Close	M1-2228-01
1-HV-4172	Accumulator 2 Liq. Space to Prim. Samp. Sys. Control Valve	A	Close	M1-2228-01
1-HV-4173	Accumulator 3 Liq. Space to Prim. Samp. Sys. Control Valve	A	Close	M1-2228-01
1-HV-4174	Accumulator 4 Liq. Space to Prim. Samp. Sys. Control Valve	A	Close	M1-2228-01
1-HV-4175	Accumulator 1 through 4 Liq. Space to Prim. Samp. Sys. Control Valve	B	Close	M1-2228-01A
1-HV-4176	Pressurizer Stm. Space to Prim. Samp. Sys. Control Valve	B	Close	M1-2228-01A
1-HV-4178	RHR Loop to Prim. Samp. Sys. Control Valve	A	Close	M1-2228-02
1-HV-4179	RHR Loop to Prim. Samp. Sys. Control Valve	B	Close	M1-2228-02
1-HV-4182	Containment Sump to Prim. Samp. Sys. Control Valve	A	Close	M1-2228-05
1-HV-5157	Containment Sump Drain Valve	B	Close	M1-2238-02

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 4 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
1-HV-5158	Containment Sump Drain Valve	A	Close	M1-2238-02
1-HV-5544	Containment Atmos. to Rad. Monitor Sys. Control Valve	B	Close	M1-2301-06
1-HV-5545	Containment Atmos. to Rad. Monitor Sys. Control Valve	A	Close	M1-2301-06 (M2-2301-04)
1-HV-5546	Containment Rad. Monitor Sys. Exh. Control Valve	B	Close	M1-2301-06 (M2-2301-04)
1-HV-5547	Containment Rad. Monitor Sys. Exh. Control Valve	A	Close	M1-2301-06 (M2-2301-04)
1-7126	RC Drain Tank Vent Valve	A	Close	M1-2264-06
1-7136	RC Drain Tank Disch. Pump Suct. Isolation Valve	B	Close	M1-2264-07
1-7150	RC Drain Tank Vent Isolation Valve	B	Close	M1-2264-09
1-HV-7311	PASS to RC Drain Tank Control Valve	B	Close	M1-2264-10
1-HV-7312	PASS to RC Drain Tank Control Valve	A	Close	M1-2264-10
1-8026	Pressurizer Rel. Tk. Vent to WPS Isolation Valve	A	Close	M1-2251-08
1-8027	Pressurizer Rel. Tk. Vent to WPS Isolation Valve	B	Close	M1-2251-08
1-8047	Rctr. Makeup Wtr. to Pressurizer Rel. Tank Isolation Valve	B	Close	M1-2251-09

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 5 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
1-LCV-0459	Letdown Isolation Valve	A	None	M1-2253-08
1-LCV-0460	Letdown Isolation Valve	A	None	M1-2253-08
1-8100	RCP Seal Wtr. Isolation Valve	B	Close	M1-2253-09
1-8112	RCP Seal Wtr. Isolation Valve	A	Close	M1-2253-09
1-8152	Letdown Line Isolation Valve	B	Close	M1-2253-14
1-8160	Letdown Line Isolation Valve	A	Close	M1-2253-15
1-HV-8220	Charging Pump Suction High Point Vent Valve	A	Close	M1-2255-07
1-HV-8221	Charging Pump Suction High Point Vent Valve	B	Close	M1-2255-07
1-8888	Accumulator Fill Line Control Valve	B	Close	M1-2263-11
1-8871	Test Line Header Control Valve	A	Close	M1-2262-05
1-8823	Safety Injection Pump Test Line Control Valve	A	Close	M1-2263-08
1-8824	Safety Injection Pump Test Line Control Valve	A	Close	M1-2263-08
1-8825	Safety Injection Pump Test Line Control Valve	A	Close	M1-2263-08
1-8843	Charging Pump Test Line Isolation Valve	B	Close	M1-2261-08

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 6 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
1-8880	Accumulator N_2 Supply Isolation Valve	B	Close	M1-2262-07
1-8881	Safety Injection Pump Hot Leg Test Line Control Valve	A	Close	M1-2263-10
1-8890A	RHR Pump Test Line Control Valve	A	Close	M1-2263-11
1-8890B	RHR Pump Test Line Control Valve	B	Close	M1-2263-11
1-8964	Test Line Header Control Valve	B	Close	M1-2262-08
1-HV-5365	Demineralized Water, Containment Isolation Valve	B	Close	M1-2242-01
1-HV-5366	Demineralized Water, Containment Isolation Valve	A	Close	M1-2242-01
1-HV-4710	CCW System, Containment Isolation Valve	B	Close	M1-2231-05
1-HV-4711	CCW System, Containment Isolation Valve	B	Close	M1-2231-05
1-HV-4725	CCW System, Containment Isolation Valve	A	Close	M1-2231-07
1-HV-4726	CCW System, Containment Isolation Valve	B	Close	M1-2231-07
1-HV-5536	Containment Purge Air Supply Isolation Valve	B	None	M1-2301-04 (M2-2301-02)
1-HV-5537	Containment Purge Air Supply Isolation Valve	A	None	M1-2301-04 (M2-2301-02)

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 7 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
1-HV-5538	Containment Purge Air Exh. Isolation Valve	B	None	M1-2301-04 (M2-2301-02)
1-HV-5539	Containment Purge Air Exh. Isolation Valve	A	None	M1-2301-04 (M2-2301-02)
1-HV-5540	Containment Hydrogen Controlled Purge Exh. Isolation Valve	B	Close	M1-2301-05 (M2-2301-3)
1-HV-5541	Containment Hydrogen Controlled Purge Exh. Isolation Valve	A	Close	M1-2301-05 (M2-2301-03)
1-HV-5542	Containment Hydrogen Controlled Purge Supply Isolation Valve	B	Close	M1-2301-05 (M2-2301-03)
1-HV-5543	Containment Hydrogen Controlled Purge Supply Isolation Valve	A	Close	M1-2301-05 (M2-2301-03)
1-HV-5548	Containment Purge Relief Disch. Isolation Valve	B	Close	M1-2301-07 (M2-2301-05)
1-HV-5549	Containment Purge Relief Disch. Isolation Valve	A	Close	M1-2301-07 (M2-2301-05)
1-HV-5556	Containment Atmos. Samp. Ret. to Containment Isolation Valve	A	Close	M1-2301-08 (M2-2301-06A)

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 8 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
1-HV-5557	Containment Atmos. Samp. Ret. to Containment Isolation Valve	B	Close	M1-2301-08 (M2-2301-06)
1-HV-5559	Containment Atmos. Samp. from Containment Isolation Valve	B	Close	M1-2301-08 (M2-2301-06)
1-HV-5561	Containment Atmos. Samp. from Containment Isolation Valve	B	Close	M1-2301-08 (M2-2301-06)
1-HV-5562	Exh. Header to Hydrogen Purge Fans Control Valve	B	Close	M1-2301-09 (M2-2301-07)
1-HV-5563	Exh. Header to Hydrogen Purge Fans Control Valve	B	Close	M1-2301-09 (M2-2301-07)
1-HV-6082	Chilled Wtr. Ret. Hdr. to Circulation Pump Control Valve	B	Close	M1-2307-05
1-HV-6083	Chilled Wtr. Ret. Hdr. to Circulation Pump Control Valve	A	Close	M1-2307-05
1-HV-6084	Chilled Wtr. Supply Hdr. to Containment Unit Coolers Control Valve	B	Close	M1-2307-06
1-HV-5558	Containment Atmos. Samp. from Containment Isolation Valve	A	Close	M1-2301-08A (M2-2301-06A)
1-HV-5560	Containment Atmos. Samp. from Containment Isolation Valve	A	Close	M1-2301-08A (M2-2301-06A)

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 9 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
CP1-AFAPMD-01	Motor Driven Aux. FW Pump	A	Start	2323-M1-2206-01
CP1-AFAPMD-02	Motor Driven Aux. FW Pump	B	Start	M1-2206-01
CP1-DDAPRM-01	Reactor Make-Up Water Pump	A	Stop	M1-2241-03
CPX-DDAPRM-01	Reactor Make-Up Water Pump	B	Stop	M1-2241-03
CP1-CHCICE-05	HVAC Water Chiller	A	Start	E1-0033 Sh. 29
CP1-CHCICE-06	HVAC Water Chiller	B	Start	E1-0033 Sh. 31
CPX-VAACUP-01	UPS and Distr. Room A/C Unit	A	Start	M1-2313-01
CPX-VAACUP-02	UPS and Distr. Room A/C Unit	B	Start	M1-2313-01
CP1-VAAUSE-15	Electrical Area Fan	B	Start	M1-2302-08
CP1-VAAUSE-16	Electrical Area Fan	B	Start	M1-2302-08
CP1-VAAUSE-17	Electrical Area Fan	A	Start	M1-2302-08
CP1-VAAUSE-18	Electrical Area Fan	A	Start	M1-2302-08
CPX-VAACCR-01	Control Room A/C Unit	A	Start	M1-2304-05
CPX-VAACCR-02	Control Room A/C Unit	A	Start	M1-2304-05

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 10 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
CPX-VAACCR-03	Control Room A/C Unit	B	Start	M1-2304-05
CPX-VAACCR-04	Control Room A/C Unit	B	Start	M1-2304-05
CPX-SFAPSF-01	Spent Fuel Pool Pump	A	Stop	M1-2235-01
CPX-SFAPSF-02	Spent Fuel Pool Pump	B	Stop	M1-2235-01
TBX-RHAPRH-01	Residual Heat Removal Pump No. 1	A	Start	M1-2260-01
TBX-RHAPRH-02	Residual Heat Removal Pump No. 2	B	Start	M1-2260-01
TBX-SIAPSI-01	Safety Injection Pump No. 1	A	Start	M1-2263-01
TBX-SIAPSI-02	Safety Injection Pump No. 2	B	Start	M1-2263-01
TBX-CSAPCH-01	Charging Pump No. 1	A	Start	M1-2255-01
TBX-CSAPCH-02	Charging Pump No. 2	B	Start	M1-2255-01
1-LCV-112B	Volume Control Tank Isolation Valve	A	Close	M1-2255-07
1-LCV-112C	Volume Control Tank Isolation Valve	B	Close	M1-2255-07
1-LCV-112D	SIS Refueling Water to Charging Pump Header, Isolation Valve	A	Open	M1-2255-08
1-LCV-112E	SIS Refueling Water to Charging Pump Header, Isolation Valve	B	Open	M1-2255-08

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 11 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
1-8105	Charging Pump Discharge to RCS Isolation Valve	B	Close	M1-2255-18
1-8106	Charging Pump Discharge to RCS Isolation Valve	A	Close	M1-2255-18
1-8110	Charging Pump Miniflow Isolation Valve	A	Close	M1-2255-19
1-8111	Charging Pump Miniflow Isolation Valve	B	Close	M1-2255-19
1-8800A	RWST Isolation Valve to SFPCS Pump	A	Close	M1-2261-05
1-8800B	RWST Isolation Valve to SFPCS Pump	B	Close	M1-2261-05
1-8801A	High Head Safety Injection Valve	A	Open	M1-2261-05
1-8801B	High Head Safety Injection Valve	B	Open	M1-2261-05
1-8808A	SIS Accumulator #1 Isolation Valve	A	Open	M1-2262-04
1-8808B	SIS Accumulator #2 Isolation Valve	B	Open	M1-2262-04
1-8808C	SIS Accumulator #3 Isolation Valve	A	Open	M1-2262-04
1-8808D	SIS Accumulator #4 Isolation Valve	B	Open	M1-2262-04
1-8811A	Sump Control Valve to RHR Pump-01	A	Open	M1-2263-06
1-8811B	Sump Control Valve to RHR Pump-02	B	Open	M1-2263-06

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 12 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
1-8202A	Suction Stabilizer Vent Isolation Valve	A	Close	M1-2255-20
1-8202B	Suction Stabilizer Vent Isolation Valve	B	Close	M1-2255-20
1-8210A	Nitrogen Supply to Suction Stabilizer Tank	A	Close	M1-2255-20
1-8210B	Nitrogen Supply to Suction Stabilizer Tank	B	Close	M1-2255-20
1-A	Feedwater Pump Turbine	A/B	Trip	M1-2203-02
1-B	Feedwater Pump Turbine	A/B	Trip	M1-2203-02
1-HV-2484	Condensate Makeup Tank to Condensate System Isolation Valve	A	Close	M1-2206-09
1-HV-2397	SG #1 Blowdown Isolation Valve	A/B	Close	M1-2202-06
1-HV-2397A	SG #1 Blowdown Isolation Valve	B	Close	M1-2202-06A
1-HV-2398	SG #2 Blowdown Isolation Valve	A/B	Close	M1-2202-06
1-HV-2398A	SG #2 Blowdown Isolation Valve	B	Close	M1-2202-06A
1-HV-2399	SG #3 Blowdown Isolation Valve	A/B	Close	M1-2202-06
1-HV-2399A	SG #3 Blowdown Isolation Valve	B	Close	M1-2202-06A
1-HV-2400	SG #4 Blowdown Isolation Valve	A/B	Close	M1-2202-06

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 13 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
1-HV-2400A	SG #4 Blowdown Isolation Valve	B	Close	M1-2202-06A
1-HV-2401A	SG #1 Drum Sample Isolation Valve	A	Close	M1-2202-06B
1-HV-2401B	SG #1 Blowdowm Sample Isolation Valve	A	Close	M1-2202-06B
1-HV-2402A	SG #2 Drum Sample Isolation Valve	A	Close	M1-2202-06B
1-HV-2402B	SG #2 Blowdown Sample Isolation Valve	A	Close	M1-2202-06B
1-HV-2403A	SG #3 Drum Sample Isolation Valve	A	Close	M1-2202-06B
1-HV-2403B	SG #3 Blowdown Sample Isolation Valve	A	Close	M1-2202-06B
1-PV-2453A	MDAFW To SG1 Flow Control Valve	A	Trip to Open with 10 sec Operator Lockout	M1-2206-03
1-PV-2453B	MDAFW to SG2 Flow Control Valve	A	Trip to Open with 10 sec. Operator Lockout	M1-2206-03
1-PV-2454A	MDAFW to SG3 Flow Control Valve	B	Trip to Open with 10 sec Operator Lockout	M1-2206-03A
1-PV-2454B	MDAFW to SG4 Flow Control Valve	B	Trip to Open with 10 sec. Operator Lockout	M1-2206-03A
1-HV-2404A	SG #4 Drum Sample Isolation Valve	A	Close	M1-2202-06B

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 14 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
1-HV-2404B	SG #4 Blowdown Sample Isolation Valve	A	Close	M1-2202-06B
1-HV-2485	Condensate Make-up Tank to Condensate System Isolation Valve	B	Close	M1-2206-09
1-HV-2405	SG #1 Sample Isolation Valve	B	Close	M1-2202-06C
1-HV-2406	SG #2 Sample Isolation Valve	B	Close	M1-2202-06C
1-HV-2407	SG #3 Sample Isolation Valve	B	Close	M1-2202-06C
1-HV-2408	SG #4 Sample Isolation Valve	B	Close	M1-2202-06C
CP1-CTAPCS-01	Containment Spray Pump	A	Start	M1-2232-03
CP1-CTAPCS-03	Containment Spray Pump	A	Start	M1-2232-03
CP1-CTAPCS-02	Containment Spray Pump	B	Start	M1-2232-03
CP1-CTAPCS-04	Containment Spray Pump	B	Start	M1-2232-03
1-HV-5640A	Motor Driven Aux. FWP Room Supply Damper (Unit 1 Only)	BB	None	M1-2302-05
1-HV-5640B	Motor Driven Aux. FWP Room Exhaust Valve (Unit 1 Only)	BB	None	M1-2302-05
1-HV-5641A	Motor Driven Aux. FWP Room Supply Damper (Unit 1 Only)	AA	None	M1-2302-05
1-HV-5641B	Motor Driven Aux. FWP Room Exhaust Valve (Unit 1 Only)	AA	None	M1-2302-05

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 15 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
1-HV-5658A	RHR Pump Room Supply Damper	AA	None	M1-2302-05
1-HV-5658B	RHR Pump Room Exhaust Valve	AA	None	M1-2302-05
1-HV-5659A	Containment Spray Pump Room Supply Damper	AA	None	M1-2302-05
1-HV-5659B	Containment Spray Pump Room Exhaust Valve	AA	None	M1-2302-05
1-HV-5660A	Safety Injection Pump Room Supply Damper	AA	None	M1-2302-05
1-HV-5660B	Safety Injection Pump Room Exhaust Valve	AA	None	M1-2302-05
1-HV-5663A	Safety Injection Pump Room Supply Damper	BB	None	M1-2302-05
1-HV-5663B	Safety Injection Pump Room Exhaust Valve	BB	None	M1-2302-05
1-HV-5664A	Containment Spray Room Supply Damper	BB	None	M1-2302-05
1-HV-5664B	Containment Spray Room Exhaust Valve	BB	None	M1-2302-05
1-HV-5665A	RHR Pump Room Supply Damper	BB	None	M1-2302-05
1-HV-5665B	RHR Pump Room Exhaust Valve	BB	None	M1-2302-05
X-HV-5747A	Charging Pump Room Supply Damper	BB	None	M1-2303-05A
X-HV-5747B	Charging Pump Room Exhaust Valve	BB	None	M1-2303-05A

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 16 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
X-HV-5762B	Charging Pump Room Exhaust Valve	AA	None	M1-2303-05A
X-HV-5764B	Component Cooling Water Pump Room Exhaust Valve	AA	None	M1-2303-05A
X-HV-5765A	Component Cooling Water Pump Room Supply Damper	BB	None	M1-2303-05A
X-HV-5765B	Component Cooling Water Pump Room Exhaust Valve	BB	None	M1-2303-05A
X-HV-5766A	Component Cooling Water Pump Room Supply Damper	BB	None	M1-2303-05A
X-HV-5766B	Component Cooling Water Pump Room Exhaust Valve	BB	None	M1-2303-05A
X-HV-5774B	Charging Pump Room Exhaust Valve	AA	None	M1-2303-05A
X-HV-5779A	Charging Pump Room Supply Damper	BB	None	M1-2303-05A
X-HV-5779B	Charging Pump Room Exhaust Valve	BB	None	M1-2303-05A
CPX-VAFNCB-07	Primary Plant Vent ESF Exhaust Fan	A	Start	M1-2309-01
CPX-VAFNCB-08	Primary Plant Vent ESF Exhaust Fan	B	Start	M1-2309-01
CPX-VAFNCB-21	Primary Plant Vent ESF Exhaust Fan	A	Start	M1-2309-01
CPX-VAFNCB-22	Primary Plant Vent ESF Exhaust Fan	B	Start	M1-2309-01
CP1-VAFNID-07	Battery Room Exhaust Fan	A	Start	M1-2305-04

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 17 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
CP1-VAFNID-08	Battery Room Exhaust Fan	A	Start	M1-2305-04
CP1-VAFNID-09	Battery Room Exhaust Fan	B	Start	M1-2305-04
CP1-VAFNID-10	Battery Room Exhaust Fan	B	Start	M1-2305-04
1-FV-4536	Component Cooling Water Loop 1 Recirc. Control Valve	A	Close	M1-2229-04
1-FV-4537	Component Cooling Water Loop 2 Recirc. Control Valve	B	Close	M1-2229-04
1-HV-4572	RHR Heat Exchanger Discharge Control Valve	A	Part-Open	M1-2229-06
1-HV-4573	RHR Heat Exchanger Discharge Control Valve	B	Part-Open	M1-2229-06
1-HV-4631A	CCW Non-Safeguard Loop to Primary Sampling System Valve	A	Close	M1-2230-01
1-HV-4631B	Primary Sample Sys. to CCW Return HDR Valve	A	Close	M1-2230-01
1-FV-4650A	Vent Chillers CCW Supply Control Valve	B	Close	M1-2230-02
1-FV-4650B	Vent Chillers CCW Disch. Control Valve	B	Close	M1-2230-02
CP1-CHAPCP-05	Chilled Water Recirc. Pump-05	A	Start	M1-2311-01
CP1-CHAPCP-06	Chilled Water Recirc. Pump-06	B	Start	M1-2311-01
CP1-CCAPCC-01	Component Cooling Water Pump-01	A	Start	M1-2229-03

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 18 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
CP1-CCAPCC-02	Component Cooling Water Pump-02	B	Start	M1-2229-03
CP1-MEDGEE-01	Diesel Generator -01	A	Start	E1-0067-95
CP1-MEDGEE-02	Diesel Generator -02	B	Start	E1-0067-95
CP1-SWAPSW-01	Station Service Water Pump-01	A	Start	M1-2233-01
CP1-SWAPSW-02	Station Service Water Pump-02	B	Start	M1-2233-01
X-HV-5825B	Control Room Make-Up Supply Damper	A	Shut	M1-2304-01B
X-HV-5828B	Control Room Make-Up Supply Damper	B	Shut	M1-2304-01B
X-HV-5837	Control Room Intake Damper	A	Open	M1-2304-03
X-HV-5838	Control Room Intake Damper	B	Open	M1-2304-03
X-HV-5825A	Make-Up Units Inlet Damper	A	Close	M1-2304-01
X-HV-5828A	Make-Up Units Inlet Damper	B	Close	M1-2304-01
X-HV-5831	Emergency Pressurization Units Inlet Damper	A	Open	M1-2304-02
X-HV-5834	Emergency Pressurization Units Inlet Damper	B	Open	M1-2304-02
X-HV-5839	Emergency Filtration Units Damper	A	Open	M1-2304-03

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 19 of 20)

Equipment Identification[(a)]	Description	Train	ESFAS Function	SIS Signal Drawing Number
X-HV-5840	Emergency Filtration Units Damper	B	Open	M1-2304-03
X-PV-5855	Control Room Exh. Fan Inlet Control Damper	A	Close	M1-2304-06
X-PV-5856	Control Room Exh. Fan Inlet Control Damper	B	Close	M1-2304-06
X-HV-5857	Kitchen & Toilet Exh. Fan Inlet Control Damper	A	Close	M1-2304-07
X-HV-5858	Kitchen & Toilet Exh. Fan Inlet Control Damper	B	Close	M1-2304-07
CPX-VAFNAV-37	Control Room Air Makeup Fan	A	Stop	M1-2304-01
CPX-VAFNAV-38	Control Room Air Makeup Fan	B	Stop	M1-2304-01
CPX-VAFNCB-05	Control Room Pressurization Fan	A	Start	M1-2304-02
CPX-VAFNCB-06	Control Room Pressurization Fan	B	Start	M1-2304-02
CPX-VAFNCB-23	Emergency Filtration Fan	A	Start	M1-2304-04
CPX-VAFNCB-24	Emergency Filtration Fan	B	Start	M1-2304-04
CPX-VAFNID-01	Control Room Main Exhaust Fan	A	Stop	M1-2304-06
CPX-VAFNID-02	Control Room Main Exhaust Fan	B	Stop	M1-2304-06
CPX-VAFNID-03	Control Room Complex Kitchen and Toilet Exhaust Fan	A	Stop	M1-2304-07

TABLE 7.3-4
SAFETY INJECTION ACTUATED EQUIPMENT LIST

(Sheet 20 of 20)

Equipment Identification[a]	Description	Train	ESFAS Function	SIS Signal Drawing Number
CPX-VAFNID-04	Control Room Complex Kitchen and Toilet Exhaust Fan	B	Stop	M1-2304-07
X-HV-5883	Control Room Vent Control Damper	A/B	Partial-Open	M1-2304-13
1-8511A	Charging Pump Alternate Mini-flow Isolation Valve	A	Open	M1-2255-21
1-8511B	Charging Pump Alternate Mini-flow Isolation Valve	B	Open	M1-2255-21
--	Containment Personnel Airlock Hydraulic Unit	A/B	Trip	M1-2245-01 (Note 1)

a) This table lists only Unit 1 and Common safety related equipment actuated directly by a Safety Injection signal. Unless otherwise noted, Unit 2 equipment identification and drawing numbers are the same except for unit prefix. For any subsidiary equipment, in turn started by this equipment, refer to applicable drawings.

Notes:

1: The Train A trip is accomplished by tripping the Class 1E feeder breaker to MCC 1EB1-2 at the Train A 480V switchgear 1EB1. The Train B trip is accomplished by tripping Class 1E Train B circuit breaker CP1-BSDSEB-01 in the feeder circuit of the hydraulic unit fed from MCC 1EB1-2.

TABLE 7.3-5
ESFAS ACTUATED COMPONENTS OF THE CONTAINMENT SPRAY SYSTEMS AND ITS SUPPORTING SYSTEMS

(Sheet 1 of 3)

Equipment Identification[(a)]	Description	ESF Train	ESFAS Signal Function	Drawing Number
CP1-CTAPCS-01	Containment Spray Pump No. 1-1	A	Start	M1-2232-03
CP1-CTAPCS-02	Containment Spray Pump No. 1-2	B	Start	M1-2232-03
CP1-CTAPCS-03	Containment Spray Pump No. 1-3	A	Start	M1-2232-03
CP1-CTAPCS-04	Containment Spray Pump No. 1-4	B	Start	M1-2232-03
1-HV-4776	Containment Spray Heat Exchanger-01 Outlet Valve	A	Open	M1-2232-04
1-HV-4777	Containment Spray Heat Exchanger-02 Outlet Valve	B	Open	M1-2232-04
1-LV-4754	Chemical Additive Tank Discharge Valve	A	Open	M1-2232-01
1-LV-4755	Chemical Additive Tank Discharge Valve	B	Open	M1-2232-01
1-HV-4572	RHR Heat Exchanger-01 Outlet Control Valve	A	Part-Open	M1-2229-06
1-HV-4573	RHR Heat Exchanger-02 Outlet Control Valve	B	Part-Open	M1-2229-06
1-HV-4574	Containment Spray Heat Exchanger Discharge Control Valve	A	Part-Open	M1-2229-06
1-HV-4575	Containment Spray Heat Exchanger Discharge Control Valve	B	Part-Open	M1-2229-06

TABLE 7.3-5
ESFAS ACTUATED COMPONENTS OF THE CONTAINMENT SPRAY SYSTEMS AND ITS SUPPORTING SYSTEMS

(Sheet 2 of 3)

Equipment Identification[(a)]	Description	ESF Train	ESFAS Signal Function	Drawing Number
1-HV-4512	CCW Non-Safeguards Loop Return Header Control Valve	A	Close	M1-2229-02
1-HV-4513	CCW Non-Safeguards Loop Return Header Control Valve	B	Close	M1-2229-02
1-HV-4514	CCW Non-Safeguards Loop Return Header Control Valve	A	Close	M1-2229-04B
1-HV-4515	CCW Non-Safeguards Loop Return Header Control Valve	B	Close	M1-2229-02
1-HV-4524	CCW Heat Exchanger to Non-Safeguards Loop Isolation Valve	A	Close	M1-2229-04B
1-HV-4525	CCW Heat Exchanger to Non-Safeguards Loop Isolation Valve	B	Close	M1-2229-02
1-HV-4526	CCW Heat Exchanger to Non-Safeguards Loop Isolation Valve	A	Close	M1-2229-04B
1-HV-4527	CCW Heat Exchanger to Non-Safeguards Loop Isolation Valve	B	Close	M1-2229-02
1-HV-4696	CCW System Containment Isolation Valve	A	Close	M1-2231-02
1-HV-4699	CCW System Isolation Valve	A	Close	M1-2231-03
1-HV-4700	CCW System Containment Isolation Valve	B	Close	M1-2231-03

TABLE 7.3-5
ESFAS ACTUATED COMPONENTS OF THE CONTAINMENT SPRAY SYSTEMS AND ITS SUPPORTING SYSTEMS

(Sheet 3 of 3)

Equipment Identification[a]	Description	ESF Train	ESFAS Signal Function	Drawing Number
1-HV-4701	CCW System Containment Isolation Valve	A	Close	M1-2231-03
1-HV-4708	CCW System Containment Isolation Valve	B	Close	M1-2231-05
1-HV-4709	CCW System Containment Isolation Valve	B	Close	M1-2231-05

a) This table lists only Unit 1 safety related equipment actuated directly by a Spray Actuation or Containment Isolation Phase B signal. Unit 2 equipment identification and drawing numbers are the same except for unit prefix. For any subsidiary equipment in turn started by this equipment, refer to applicable drawings.

TABLE 7.3-6
STEAMLINE ISOLATION ACTUATED EQUIPMENT LIST

Equipment Identification[a]	Description	ESF Train	Function	ESFAS Signal Drawing Number
1-HV-2333A	Steam Generator #1 MSIV	A/B	Close	M1-2202-02
1-HV-2334A	Steam Generator #2 MSIV	A/B	Close	M1-2202-02
1-HV-2335A	Steam Generator #3 MSIV	A/B	Close	M1-2202-02
1-HV-2336A	Steam Generator #4 MSIV	A/B	Close	M1-2202-02
1-HV-2409	Main Steam Line #1 Before MSIV Drip Pot Isolation Valve	A/B	Close	M1-2202-07
1-HV-2410	Main Steam Line #2 Before MSIV Drip Pot Isolation Valve	A/B	Close	M1-2202-07
1-HV-2411	Main Steam Line #3 Before MSIV Drip Pot Isolation Valve	A/B	Close	M1-2202-07
1-HV-2412	Main Steam Line #4 Before MSIV Drip Pot Isolation Valve	A/B	Close	M1-2202-07

a) This table lists only Unit 1 safety related equipment actuated directly by a Steam Line Isolation signal. Unit 2 equipment identification and drawing numbers are the same except for unit prefix.

7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

The systems required for safe shutdown are controlled and monitored by instrumentation channels associated with those systems in both the Nuclear Steam Supply System (NSSS) and balance of plant (BOP) systems. These systems are normally aligned to serve a variety of operational functions, including startup and shutdown, as well as protective functions. There are no uniquely identified safe shutdown systems per se. However, prescribed procedures for securing and maintaining the plant in a safe condition can be instituted by appropriate alignment of selected systems.

Two kinds of shutdown conditions are addressed in this section: hot standby and cold shutdown. Hot standby is a stable condition of the reactor achieved shortly after a programmed or emergency shutdown of the plant and is the safe shutdown design basis for CPNPP. Cold shutdown is a stable condition of the plant achieved after the residual heat removal process has brought the primary coolant temperature below 200°F. In either case, the reactivity control systems maintain a subcritical condition of the core. The plant technical specifications explicitly define both hot standby and cold shutdown conditions.

The instrumentation and control functions required to be aligned for maintaining safe shutdown of the reactor that are discussed in this section are the minimum number under nonaccident conditions. These functions permit the necessary operations that will:

1. Prevent the reactor from achieving criticality in violation of the technical specifications.

2. Provide an adequate heat sink so that design and safety limits are not exceeded.

The designation of systems that can be used for safe shutdown depends on identifying those systems which provide the following capabilities:

1. Reactivity control - reactor trip and boration

2. Decay heat removal - auxiliary feedwater (AFW) supply and residual heat removal (RHR) [The RHRS is required to achieve and maintain cold shutdown.]

7.4.1 DESCRIPTION

In the event of a unit shutdown, the unit will be brought to and maintained at a safe shutdown condition from the main Control Room or the Hot Shutdown Panel (see Section 7.4.1.3).

The portions of the Reactor Trip System required to achieve the shutdown condition are described in Section 7.2. The minimum systems, support systems, component controls, and monitoring indicators required under nonaccident conditions to maintain hot standby are tabulated and discussed in Section 7.4.1.1 and those required to maintain cold shutdown are tabulated and discussed in Section 7.4.1.2. Shutdown from outside the Control Room is discussed in Section 7.4.1.3.

7.4.1.1 Hot Standby

Hot standby is maintained by providing decay heat removal via at least one steam generator. The following systems, support systems, and monitoring indicators are required for hot standby:

1. Essential Systems

   a. Auxiliary Feedwater System (AFS)

   b. Steam Generator safety valves

   c. Chemical and Volume Control System (CVCS), boron addition portion.

2. Support Systems

   a. Station Service Water System (Sections 9.2.1 and 7.3.1.1.4)

   b. Component Cooling Water System (Sections 9.2.2 and 7.3.1.1.4)

   c. Onsite power system (Sections 8.3 and 7.3.1.1.4), including diesel generators (Section 9.5)

   d. Control Room ventilation system (Sections 9.4.1 and 7.3.1.1.4)

   e. ESF Ventilation System (Sections 9.4.5 and 7.3.1.1.4)

   f. Safety Chilled Water System (Sections 9.4F and 7.3.1.1.4)

   g. UPS Ventilation System (Sections 9.4C.8)

3. Monitoring Indicators

   a. Steam Generators (SG's)

      1. Water level for each SG

      2. Pressure for each SG

   b. Reactor Coolant System

      1. Pressurizer water level

      2. Pressurizer pressure

   c. Condensate storage tank level

7.4.1.1.1 Auxiliary Feedwater System

At hot standby, decay heat is removed by supplying auxiliary feedwater to the steam generators. Heat is dumped to the condenser (if offsite power is available), to the atmosphere via the steam generator power-operated relief valves, or to the atmosphere via the steam generator safety valves.

For a description of the Auxiliary Feedwater System refer to Section 10.4.9.

For a description of the Auxiliary Feedwater System control refer to Section 7.3.1.1.4, Item 5. A discussion of instrumentation is found in Section 10.4.9.5.

The system flow diagram is shown on Figure 10.4-11.

The system failure mode analysis is contained in Table 10.4-9 and the pertinent illustration is Figure 10.4-12.

7.4.1.1.2 Steam Generator Atmospheric Relief Valves and Safety Valves

For normal plant cooldown, the Steam Dump System, described in Section 10.4.4, is used to control the cooldown rate by directing steam from the steam generators to the condenser. The steam generator atmospheric relief valves enable heat removal from the steam generators to the atmosphere when the condenser is not in service. These valves, described in Section 10.3.2.2, will allow gradual cooldown of the RCS to the point where the RHRS can be employed to continue plant cooldown (less than 425 psig and 350°F).

The main steam system is protected against overpressurization by the ASME B&PV Code-certified safety valves described in Section 10.3.2.1.

In the event of loss of the Steam Dump System and loss of the steam generator atmospheric relief valves, the safety valves will be used to dump steam to the atmosphere, thereby maintaining the plant at hot standby.

1. Initiating Circuits

   A pressure transmitter and controller is provided for each steam generator atmospheric relief valve. Steam pressure developed in the SG is limited by the controller set point selected. Either automatic or manual control can be selected on the controller located in the Control Room.

   These valves are also equipped with handwheels to enable local manual operation. For operation outside the Control Room, access to the valve's control circuitry is provided and manual operation of each valve is accomplished with a local controller at the Hot Shutdown Panel.

   The initiation device for the safety valve is an intrinsic part of the valve.

2. Logic

   See instrumentation and control diagrams (ICD's) listed under "Main Steam Reheat and Steam Dump System" in Tables 1.7-1 and 1.7-2 for steam generator atmospheric relief valve control.

   The safety valves are spring-loaded valves that open on reaching the pressure set point.

3. Bypass

   There are no electrical bypasses on safety valves nor on steam generator atmospheric relief valves.

The steam generator atmospheric relief valves have manually operated isolation valves upstream of the relief valves for relief valve maintenance. Administrative procedures will assure the proper position of these isolation valves.

4. Interlocks

There are none.

5. Redundancy

The safety valves and steam generator atmospheric relief valves are redundant in that two of four steam generators are required for safe shutdown.

6. Diversity

The normally power-operated atmospheric relief valves can also be operated diversely and manually via the valve handwheel.

7. Actuated Devices

None, other than the valves themselves.

8. Supporting Systems

The following supporting systems are required for operation of steam generator atmospheric relief valves.

a. Class 1E electric power (see Section 8.3)

b. Compressed Air System (see Section 9.3.1 and Figure 9.3-1)

9. Design Basis Information

a. See Table 10.3-2 for the design basis of the main steam safety valves.

b. See Table 10.3-3 for the design basis of the steam generator atmospheric relief valves.

10. Electric Schematic Drawings

See Table 1.7-1 for Unit 1 and common and Table 1.7-2 for Unit 2 schematics (electrical) associated with “Main Steam Reheat & Steam Dump System.”

11. Portions of System Not Required for Safety

The steam generator atmospheric relief valves and pressure transmitter output indication displayed on the control board are not required for safety.

7.4.1.1.3 Chemical and Volume Control System, Boron Addition Portion

The functions of the CVCS discussed in Section 9.3.4 are those associated with normal operation. Safe and economical operation design parameters (see Table 9.3-6) dictate the design of the CVCS for normal operation. For the safety evaluation of the overall CVCS operation refer to Section 9.3.4.1.3 and Table 9.3-9 for the failure modes and effects analysis (FMEA). If safe shutdown operation alone is to be considered, then the primary functions of the CVCS are that it provide a means, along with the proper operator action, to maintain adequate shutdown margin by sufficiently borating the core and to maintain pressurizer level. These functions are those required to maintain adequate Reactor Coolant System (RCS) inventory. The instrumentation, control and electrical features associated with maintaining adequate RCS inventory are those applied to the following groups of equipment:

1. Boric acid transfer pumps

2. Centrifugal charging pumps

3. Letdown orifice isolation valves

Further considerations, as would apply to one unit, are as follows:

1. Initiating Circuits

   Initiation is by automatic or manual commands. For discussion of automatic commands of the CVCS proper, refer to Sections 9.3.4 and 9.3.4.1.2.3, and for a discussion of the pressurizer water level control portion, see Section 7.7. Maintenance of hot standby and cold shutdown is discussed in 9.3.4.1.2.6. Manual control may be taken either in the Control Room or outside the Control Room at the Hot Shutdown Panel. For the instrumentation application, refer to Section 9.3.4.1.5.

2. Logic

   At the Shutdown Transfer Panel (Train A) and Hot Shutdown Panel (HSP) (Train B), operator action may transfer control of the boric acid transfer pumps, centrifugal charging pumps and letdown orifice isolation valves from the Control Room to the Hot Shutdown panel. At this location, start-stop operation of the pumps and open-close operation of the valves in question can then be undertaken. If the redundant normal suction paths to centrifugal charging pumps that establish boration are not available, normally closed motor operated valve 1-8104 (refer to Figure 9.3-10) can be opened either remotely in the Control Room or by handwheel at the local station. Manual or motor operated valves may also be opened to allow the centrifugal charging pumps to take suction on either the Boric Acid Storage tank or the Refueling Water Storage Tank, respectively.

3. Bypasses

   Control from the Control Room of the above groups of equipment is manually bypassed at the Shutdown Transfer Panel (Train A) and at the Hot Shutdown Panel (Train B) when control is taken over at the Hot Shutdown Panel.

4. Interlocks

With control of those above groups of equipment at the Hot Shutdown Panel, there are no interlocks imposed on their operation.

5. Redundancy

There are two centrifugal charging pumps, two boric acid transfer pumps, and three letdown orifice isolation valves.

6. Diversity

Diversity is not required for the boric acid transfer pumps for the charging pumps can take a direct suction from the storage tanks. In addition to the centrifugal charging pumps, there is a positive displacement charging pump. There are other valves in the letdown line, which, in addition to letdown orifice isolation valves, can also be used to isolate the letdown line.

7. Actuated Devices

The motor control centers for the centrifugal charging pumps and boric acid transfer pumps and the solenoid valves for the letdown orifice isolation valves are the actuation devices of the CVCS required for safe shutdown.

8. Supporting Systems

The centrifugal charging pumps, the boric acid transfer pumps, and the letdown orifice isolation valve solenoid valves are powered from Class 1E buses. Additionally, the Safety Chilled Water System supplies chilled water to the charging pump fan coil unit (see Section 9.4F) and the Station Service Water System supplies cooling water to the centrifugal charging pump lube oil coolers (see Section 9.2.1).

9. Design Basis Information

The CVCS is not specifically designed to be a protection system. Section 3, “Design Bases, “ of IEEE Standard 279 does not specifically apply to non-protection systems such as the CVCS. Portions of the CVCS, which are shared with the Safety Injection System, come under IEEE Standard 279 design bases as discussed in Section 7.3.

10. Drawings

For the CVCS flow diagram, refer to Figure 9.3-10. Also refer to the flow diagrams in Section 6.3 for shared functions of the Safety Injection System, as well as the electrical drawing list in Section 1.7.

11. Portion of System Not Required for Safety

Refer to item 9 above

7.4.1.2 Cold Shutdown

Cold shutdown is achieved following hot standby and includes passing through hot shutdown. Four key functions are required to achieve and maintain cold shutdown. They are circulation of the reactor coolant, removal of residual heat, boration, and depressurization. The required means for performing these functions are described below.

1. Circulation of the reactor coolant is provided first by natural circulation that is effected by the reactor core providing the heat source and the steam generators the heat sink, and then by the residual heat removal pumps.

2. Removal of residual heat is accomplished first via the Auxiliary Feedwater System and then via the residual heat removal heat exchanger. Hot standby is maintained by releasing steam via the safety grade steam generator safety valves. Cooldown to 350°F is accomplished by releasing steam via operation of the steam generator power-operated relief valves. Then cooldown to cold shutdown conditions is achieved with the Residual Heat Removal System. A sufficient seismic Category I supply of deaerated auxiliary feedwater to permit four hours operation at hot standby followed by cooldown to Residual Heat Removal System initiation conditions is provided by the condensate storage tank.

   A backup seismic Category I source for the Auxiliary Feedwater System is the Station Service Water System. This system provides an assured long-term supply of auxiliary feedwater.

3. Boration is accomplished using portions of the Chemical and Volume Control System. Boric acid from the boric acid tanks is supplied to the suction of the centrifugal charging pumps by the boric acid transfer pumps or the charging pumps may take a direct suction on the tanks. The centrifugal charging pumps inject the boric acid into the reactor coolant system via the safety injection flow paths or the normal charging and reactor coolant pump seal injection flow paths. As an alternate source, or for additional boration, the refueling water storage tank is available.

4. Depressurization is accomplished using portions of the Chemical and Volume Control System. Either boric acid from the boric acid tanks or refueling water from the refueling water storage tank is used as desired for depressurization with the flow path being via the centrifugal charging pumps and auxiliary spray valve to the pressurizer.

In addition to the systems required for hot standby delineated in Section 7.4.1.1, the following systems, support systems, and monitoring indicators are required to achieve and maintain cold shutdown.

1. Essential Systems

   a. Residual Heat Removal System (RHRS)

   b. Pressurizer pressure control during RCS depressurization

2. Support Systems - No additional support systems required other than those listed in Section 7.4.1.1, Number 2.

3. Monitoring Indicators

   a. RCS wide range temperature

   b. Boric acid tank level (per boric acid tank)

Additionally, the safety injection signal trip circuit must be defeated and the accumulator isolation valves closed during the later stages of plant cooldown.

7.4.1.2.1 Residual Heat Removal System (RHRS)

The Residual Heat Removal System is designed to remove residual heat from the core and reduce the temperature of the Reactor Coolant System (RCS) during plant cooldown to cold shutdown conditions. The system is permitted to be manually initiated when the reactor coolant temperature and pressure are reduced to 350°F and 400 psig or below. A detailed discussion of the RHRS is provided in Section 5.4.7. RHRS operation for reactor cooldown is discussed in Section 5.4.7.2.3. Manual actions required of the operator, both inside and outside Control Room, is discussed in Section 5.4.7.2.7. Further considerations are as follows.

1. Initiating Circuits

   Manual control of the RHRS is from the Control Room (or from the Hot Shutdown Panel for Train A). For manual actions outside the Control Room, refer to Section 5.4.7.2.7.

2. Logic

   For the logic diagram for control of the RHRS inlet isolation valves, see Figure 7.6-2.

3. Bypasses

   RHRS Bypass is indicated on the Safety System Inoperable Indicator (SSII) described in Section 7.1.2.6 and typically illustrated in Figure 7.1-4. Isolation of the RHRS cannot be manually bypassed unless permissive conditions have been automatically met as described in Section 7.6.2.

4. Interlocks

   For discussion of the RHRS inlet isolation valves interlocks, refer to Section 7.6. Section 5.4.7.2.7 discusses application of the single failure criteria.

5. Redundancy

   Two independent residual heat removal pumps are provided, either of which can provide the necessary heat removal capacity for the RCS for the safe shutdown condition. Each RHR pump is powered from a separate Class 1E bus.

6. Diversity

For opening permissives of the RHR inlet isolation valves, diverse RCS pressure transmitters, made by different manufacturers, are used. There is no other diversity in the RHRS control.

7. Actuated Devices

Electrical control equipment for the RHRS pumps, the mini-flow control, and the RHRS heat exchanger are the principal actuated devices.

8. Supporting Systems

The RHRS is powered from Class 1E buses. The RHRS heat exchangers and pumps are cooled with component cooling water (see Section 9.2.2).

9. Design Basis Information

The RHRS is not specifically designed as a protection system. Section 3, "Design Basis," of IEEE Standard 279 does not specifically apply to non-protection systems like the RHRS. Portions of the Safety Injection System which are shared with the RHRS came under IEEE Standard 279 design basis as discussed in Section 7.3.

10. Drawings

For the RHRS flow diagram, refer to Figures 5.4-6 and 5.4-7. For the RHRS inlet isolation valve interlocks, refer to Figure 7.6-2. Refer to the Section 1.7 list for applicable electrical drawings.

11. Portion of System Not Required for Safety

Refer to item 9 above.

7.4.1.2.2 Pressurizer Pressure Control

Pressurizer heater control is provided to maintain the RCS at operating pressure following a reactor trip to prevent excessive cooling of the pressurizer fluid and subsequent depressurization of the system. Normal operation is automatic via the proportional and backup heaters, as described in Section 7.7. If, for any reason, the normal pressure-regulating system is not available, the operator will control pressure with the backup heater groups in the pressurizer by manual ON-OFF control switches. Air operated valve 1-8145 in the auxiliary spray flow path, with manual control in the Control Room, provides spray for depressurizing when normal pressurizer spray control is not available. Means for depressurizing the RCS are also available from the pressurizer power-operated relief valves, with manual control in the Control Room, as well as from the normal pressurizer pressure spray control, which is active when the pressurizer pressure control system is operating. This pressurizer pressure control system, which also automatically controls the pressurizer heaters, as described in Section 7.7, is non-safety related. The pressurizer safety valves, which prevent the RCS from exceeding its design pressure, are safety-related but are self- activated and do not require instrumentation, control, and electrical circuitry for operation.

1. Initiating Circuits

   In normal automatic operation, the pressurizer pressure control system is controlled by pressurizer pressure transmitters. In addition, the backup heater groups are provided with direct manual control by the operator.

2. Logic

   See Figures 7.2-1 (sheets 11 and 12) and 7.7-4.

3. Bypass

   The control circuit provides no bypass of the manual backup heater control function other than maintenance provisions.

4. Interlocks

   All pressurizer heater groups are connected with a low-level switch to cut off power to the heaters on pressurizer low-low water level, thereby preventing heater damage. This interlock is not used when manual control of the pressurizer backup heaters is transferred to the Hot Shutdown Panel.

5. Redundancy

   Two sources of power for backup heater groups are provided, either of which can provide the necessary energy input to the pressurizer fluid to develop the requisite pressure for the safe shutdown condition. Either of two power-operated relief valves will perform the depressurization function.

6. Diversity

   No diversity of control of power supply is provided between the backup heater groups. Diversity of depressurization is provided by power-operated relief valves, safety valves, spray valves, and auxiliary spray valves.

7. Actuated Devices

   The electrical control equipment for the pressurizer backup heater groups, power-operated relief valves, safety valves, spray valves, and auxiliary spray valves are the actuated devices.

8. Supporting Systems

   Provisions have been included to feed the pressurizer backup heaters from independent Class 1E power supplies. The pressurizer power-operated relief valves and the pressurizer auxiliary spray valve utilize air from the Instrument Air System and control power from Class 1E DC buses.

9. Design Basis Information

Section 3, “Design Basis,” of IEEE Standard 279 does not apply because the pressurizer pressure control system, except for the safety valves, is not designed as a safety system. The design basis is derived from operational objectives. The safety valves are self actuated.

10. Drawings

For piping and instrumentation flow diagrams for the pressurizer pressure control system, refer to Sections 5.4.10 and 9.8.4.1. Figure 7.2-1, sheets 11 and 12, illustrate the logic.

11. Portions of System Not Required for Safety

Refer to item 9 above.

7.4.1.3 Shutdown From Outside the Control Room

A common Control Room is provided that contains all controls and instrumentation necessary for the operation of Units 1 and 2 reactors, turbine-generators, and auxiliary and emergency systems under normal or accident conditions. Sufficient radiation shielding, containment integrity, missile protection and habitability provisions are provided to permit access, exit, and continued occupancy of the control room for the duration of accident conditions such that aggregate radiation exposure to personnel would be below that specified by 10CFR50, Appendix A, General Design Criterion 19.

Considering the detailed station design provisions to ensure continuous Control Room access, it is unlikely that the necessity could arise for evacuation of the Control Room. Nevertheless, provisions have been made to maintain the reactors in a safe hot standby condition if access to the Control Room is lost. Hot standby is maintained as described in Section 7.4.1.3.2. Furthermore, cold shutdown can be achieved from outside the Control Room through the use of suitable procedures as described in Section 7.4.1.3.3.

7.4.1.3.1 Design Criteria

In designing for safe reactor shutdown in the event of Control Room evacuation, the following design criteria are applied.

1. Access back into the Control Room will generally be achieved prior to the initiation of cold shutdown except for a fire that destroys the Control Room or either Cable Spreading Room, or the Control Room HVAC Mechanical Equipment Room. The capability for bringing the reactors to cold shutdown conditions exist outside the Control Room through the use of suitable procedures and secondary controls as described in Section 7.4.1.3.3.

2. Except for a fire in the alternate shutdown areas (Control Room, Cable Spreading Rooms, or Control Room HVAC Mechanical Equipment Room), Control Room evacuation is initiated for an undefined cause (for example, control room environment not habitable) and the event which causes Control Room evacuation does not degrade Control Room equipment.

3. The design basis for Control Room evacuation does not consider a concurrent Condition II, III, or IV event, nor a single failure. However, loss of offsite power has been considered.

4. For five specific plant fires, shutdown capability is provided as follows:

Fire Location	Loss	Shutdown From
Unit 1 or Unit 2 Cable Spreading Room (CSR)	Both Trains	Unit 1 and Unit 2 Hot Shutdown Panel using Train A, Shutdown Transfer Panel transfer and local controls.
Control Room (CR)	Both Trains	Unit 1 and Unit 2 Hot Shutdown Panel using Train A, Shutdown Transfer Panel transfer and local controls.
Control Room HVAC Mechanical Equipment Room	Both Trains	Unit 1 and Unit 2 Hot Shutdown Panel using Train A, Shutdown Transfer Panel transfer and local controls.
Unit 1 or Unit 2 Hot Shutdown Panel (HSP)	Train B	Control Room using Train A
Shutdown Transfer Panel (STP)	Train A	Control Room using Train B

For any other postulated plant fire, shutdown is accomplished from the Control Room utilizing surviving equipment.

5. Except for a fire in the alternate shutdown areas, loss of safety system redundancy does not occur as a result of the event requiring control room evacuation and all equipment in the control room and all automatic controls continue to function. To prevent any adverse impact on controls at the HSP or local control stations when Control Room is evacuated due to a fire, the surveillance test program validates the opening of isolation contacts for transfer switches used to transfer controls in the event of a control room fire.

6. The respective unit's Hot Shutdown Panel (HSP) and the Shutdown Transfer Panel (STP) including Class 1E equipment mounted on them, are designed to withstand an SSE with no loss of Class 1E function. The essential local control stations are also designed to withstand an SSE with no loss of essential functions.

7. The Hot Shutdown Panels are normally unattended and are surrounded by a locked enclosure. Opening the Hot Shutdown Panel's cabinet doors will initiate an alarm in the Control Room. The Shutdown Transfer Panels are also normally unattended and access to them is restricted via normally locked doors. Opening the Shutdown Transfer Panel's cabinet doors will initiate an alarm in the Control Room.

8. The Hot Shutdown Panels, located in the switchgear area of each Safeguards Building, at elevation 831'-6", the Shutdown Transfer Panels, located one floor below at elevation 810'-6", and other local controls are easily accessible to Control Room operators through controlled access areas.

9. Electrical separation for the Hot Shutdown Panels and the Shutdown Transfer Panels follows the same criteria as corresponding Control Room equipment. Loss of control or indication for one train for any reason will not affect its redundant counterpart.

10. Controls on the Hot Shutdown Panels (HSP) are provided with a transfer switch (at the Shutdown Transfer Panel for Train A and Hot Shutdown Panel for Train B) that transfers control of equipment from the Control Room to the Hot Shutdown Panel. Placing the Train A or Train B transfer switch in the HSP position will electrically isolate all Control Room and Cable Spreading Room equipment from the rest of the circuitry with the exception of some Train B equipment not required for alternate shutdown. Placing either the Train A or Train B switch in the HSP position will provide audible and visible indication in the Control Room and will turn off status lights on the respective main control board. Interlocks which are generated in the Control Room or Cable Spreading Rooms, such as the lockout signals from the sequencer, are also isolated when control is transferred to the Hot Shutdown Panels.

11. Each control circuit consists of cables that 1) connect the transfer switches to control switches in the Control Room, 2) connect the transfer switches to the HSP-mounted control switches, 3) connect the transfer switches to the pertinent motor control center. Each of these cables is inherently separated from its redundant counterpart. Loss of a control circuit in the Control Room/Cable Spreading Room areas does not mean loss of function since control circuits are available at the HSP.

12. To prevent a single event due to a fire (e.g., short-circuit) from affecting both the Control Room controls and the HSP controls of required alternate shutdown systems, control-circuit fuses are either located in equipment accessible in such an event (e.g., 6.9 KV and 480V switchgear) or separate fuses, located in separate fire zones, are provided for both the Control Room control circuit and the HSP control circuit.

The controls and monitoring indicators on the Hot Shutdown Panels provided for hot standby are listed in Table 7.4-1. Instrumentation and controls on the Hot Shutdown Panels provided for cold shutdown are listed in Table 7.4-2. Those controls and indicators provided for Alternate Shutdown (see section 7.4.1.3.4) are identified on each table. Some controls and indicators on these tables are only provided for operating convenience. Switches provided on the Shutdown Transfer Panels are listed in Table 7.4-3.

7.4.1.3.2 Hot Standby From Outside The Control Room

Should the Control Room become uninhabitable, the reactors will be manually tripped, the neutron level and control rod position will be verified before evacuation takes place. Also, the reactors can be tripped locally at the respective reactor trip switchgear which is in close proximity to the associated Hot Shutdown Panel.

Sufficient controls are provided outside the Control Room on the Seismic Category I Hot Shutdown Panels (See Table 7.4-1) and other locations to:

- Achieve prompt hot standby of both reactors

- Maintain both units in a safe condition during hot standby.

7.4.1.3.3 Cold Shutdown From Outside the Control Room

Cold shutdown can be achieved from outside the Control Room through the use of suitable procedures and by virtue of local control of the systems listed in Section 7.4.1.2. The design bases for the achievement and maintenance of cold shutdown are as listed in Section 7.4.1.3.1. In addition, certain local manipulations of controls and initiating devices, as described below, are required.

For cold shutdown from outside the Control Room due to a Control Room or Cable Spreading Room fire, see Section 7.4.1.3.4. The basic procedure to established cold shutdown from the hot standby condition, for reasons other than fire in the Control Room or Cable Spreading Room and assuming the Control Room is uninhabitable, is as follows.

1. Transfer control from the Control Room to the Hot Shutdown Panels, as required, using the transfer switches at the Shutdown Transfer Panels for Train A and the transfer switches at the Hot Shutdown Panels for Train B.

2. Borate to the cold shutdown boron concentration using boric acid transfer pumps, if available, and charging pumps.

   Location: Hot Shutdown Panels.

   Available Indications: Reactor Coolant System (RCS) boron concentration determined by sampling.

3. Cooldown the RCS by use of the steam generator power-operated atmospheric relief valves.

   Location: Hot Shutdown Panels and local patch panels or manual handwheel operation.

   Available Indications: RCS temperature, pressurizer pressure and level, steam generator level, auxiliary feedwater flow and condensate storage tank level.

4. Depressurize the RCS by throttling the pressurizer spray valve while maintaining pressurizer level.

   Location: Hot Shutdown Panels

   Available Indications: Pressurizer pressure and level, charging and letdown flow.

5. At 1900 psig in the RCS, block the low pressurizer pressure safety injection (SI) and the low steamline pressure SI signals.

   Location: Cable spreading rooms

   Available Indications: Pressurizer pressure indication on the Hot Shutdown Panels.

6. At less than 1000 psig in the RCS, close the accumulator discharge isolation valves. Rack out the safety injection pump and containment spray pump breakers at approximately 350°F and 200°F respectively.

   Location: Switchgear and motor control centers.

   Available Indications: Pressurizer pressure indication on the Hot Shutdown Panels.

7. At less than 350°F and RCS pressure less than RHRS operational pressure, align the RCS for cooldown with the Residual Heat Removal System.

   Location: Switchgear and Hot Shutdown Panels.

   Available Indications: RCS pressure indication and RCS temperature indication on the Hot Shutdown Panel.

7.4.1.3.4 Alternate Shutdown System

The Hot Shutdown Panels are designed to enable control to a hot standby condition if, for unspecified but non-catastrophic reasons, the Control Room (CR) had to be evacuated. The circuits required for shutdown on the Hot Shutdown Panels have been redesigned to comply with the CPNPP fire protection requirements. The present design enables control via Train A equipment even if a complete loss of the Control Room or Cable Spreading Room is postulated due to fire. Thus, the Hot Shutdown Panels, Shutdown Transfer Panels and specific portions of the plant systems noted in this section function as the Alternate Shutdown System for CPNPP for a fire in the Control Room, either Cable Spreading Room, or Control Room HVAC Mechanical Equipment Room (alternate shutdown areas).

The Hot Shutdown Panels and Shutdown Transfer Panels are each located in different fire areas which are, in turn, different from the fire areas associated with the alternate shutdown areas.

Since the postulated complete loss of either Cable Spreading Room, Control Room or Control Room HVAC Mechanical Equipment Room would also cause the loss of both Train A and Train B shutdown control and associated monitoring, alternate shutdown capability was provided to survive this highly improbable catastrophe by:

1. Providing transfer of required Train A circuits on the Shutdown Transfer Panels,

2. Providing required Train A fire safe shutdown control circuits and process monitoring circuits independent of the alternate shutdown areas, and

3. Providing monitoring circuits for required Train B fire safe shutdown components which are independent of the alternate shutdown areas equipment and cabling.

If the postulated fire occurs in the alternate shutdown areas, the transfer of Train A will take place at the Shutdown Transfer Panels and the control of the required Train A shutdown equipment is established at the Hot Shutdown Panels. For this scenario, Train A has been chosen for alternate shutdown control with certain Train B and non-safety related indications independent of the Control Room and Cable Spreading Rooms. The shutdown procedures are similar to those as described in Section 7.4.1.3.2 and 7.4.1.3.3. For cold shutdown, however, step 6 of Section 7.4.1.3.3 is carried out immediately.

To summarize, loss of the Control Room, either Cable Spreading Room or Control Room HVAC Mechanical Equipment Room will require Train A transfer from the Shutdown Transfer Panels and Train A control at the Hot Shutdown Panels. Loss of a Hot Shutdown Panel will require Train A control in the Control Room. Loss of a Shutdown Transfer Panel will require Train B control in the Control Room.

7.4.2 ANALYSIS

Hot standby is a stable plant condition that is automatically reached following a reactor trip from power. Additionally, the plant design features permit the achievement of cold shutdown as described in Section 7.4.1.2. In the unlikely event that access to the Control Room is restricted, the plant can be safely kept at hot standby by the use of the monitoring indicators and controls listed in Section 7.4.1.3 until the Control Room can be reentered. The administrative controls section of the technical specifications are immediately violated by any forced evacuation of the control room. Furthermore, cold shutdown conditions can be achieved from outside the Control Room through the use of suitable procedures as described in Sections 7.4.1.3.3 and 7.4.1.3.4 and by virtue of local control of the equipment listed in Section 7.4.1.2, in conjunction with the instrumentation and controls provided on the Hot Shutdown Panels and the Shutdown Transfer Panels (Tables 7.4-1, 7.4-2 and 7.4-3).

The discussions below demonstrate conformance to applicable General Design Criteria (GDC), Regulatory Guides, and IEEE Standard 279-1971. See also Table 7.1-2 for criteria applicable to all systems, Section 7.3, and other sections as referred to in the text.

7.4.2.1 General Analysis

1. Conformance to NRC General Design Criteria

   a. GDC 19

      The Hot Shutdown Panels and essential local control stations, discussed in Section 7.4.1.3, provide adequate controls and indications at locations outside the Control Room to maintain the reactors and the reactor coolant systems in the safe shutdown condition and to ensure decay heat removal in the event the Control Room must be evacuated.

b. GDC 34

Essential controls are provided outside the control room on the Hot Shutdown Panels to ensure adequate decay heat removal from the Reactor Coolant Systems in the event the main Control Room must be evacuated.

2. Conformance to NRC Regulatory Guides

a. RG 1.29

The Hot Shutdown Panels, Shutdown Transfer Panels, and essential local control stations are designed to withstand the effects of a Safe Shutdown Earthquake (SSE) without loss of Class 1E function or physical damage. The Hot Shutdown Panels, Shutdown Transfer Panels, and essential local control stations are classified Seismic Category I components.

b. RG 1.75

Proper separation in accordance with Regulatory Guide 1.75 and IEEE Standard 384 is maintained within the Hot Shutdown Panels for Train A, Train B and non-Class 1E Equipment and wiring.

3. Conformance to IEEE Standard 279-1971

The Hot Shutdown Panel and Shutdown Transfer Panel, including essential controls and indications, and the essential local control stations are designed to conform to applicable portions of IEEE Standard 279-1971. The control circuits at the Hot Shutdown Panel and essential local control stations are designed such that a single failure will not prevent proper protective action (maintaining safe hot standby) during postulated events. This is accomplished by providing independent Class 1E power for the fully redundant controls for the systems required for safe shutdown. The single failure criteria does not apply to postulated fires.

To prevent interaction between the redundant systems, the control channels are wired independently and separated with no electrical connections between redundant control systems. Non-Class 1E control circuits and non-Class 1E monitor circuits are electrically isolated from Class 1E controls and indications to prevent jeopardizing the reliability of the systems required for safe shutdown.

4. Demonstration of the ability of the plant to achieve safe shutdown using the minimum set of equipment designated for fire safe shutdown is provided in the fire safe shutdown analysis. Supporting analysis for equipment selection and event assumptions are provided in such documents as the WCAP-11331 “CPSES Thermal Hydraulic Analysis of Fire Safe Shutdown Scenario” dated 10/30/86.

7.4.2.2 Analysis for Shutdown From Outside the Control Room

The discussion found in Section 7.4.2.1 is applicable. The additional guides, criteria, and standards listed in Table 7.1-1 apply only to the Class 1E instrumentation and controls required for safe shutdown from outside the control room.

Also see the criteria applicability matrix, Table 7.1-2, for further information.

7.4.2.3 Consideration of Selected Plant Contingencies

7.4.2.3.1 Loss of Instrument Air Systems

Since electric-powered instrumentation is supplied from the Class 1E Power System, loss of the Instrument Air System will not degrade instrumentation required for safe shutdown. An analysis of the effect of loss of plant instrument air is provided in Section 9.3.1 and Table 9.3-3.

7.4.2.3.2 Loss of Cooling Water to Vital Equipment

Cooling water for safety-related systems is supplied by the Safety Chilled Water System (Section 9.4F), the Component Cooling Water System (Section 9.2.2), and the Station Service Water System (Section 9.2.1). Each of these systems is redundant; therefore the loss of any one cooling loop or instrumentation associated with that loop will not degrade the safety-related equipment serviced by the system. Also see the analyses presented in Sections 9.4F, 9.2.1 and 9.2.2 and Tables 9.2-1 and 9.2-5.

7.4.2.3.3 Plant Load Rejection, Turbine Trip, and Loss of Offsite Power

In the event of loss of offsite power associated with plant load rejection or turbine trip, power for safe shutdown is provided by the onsite Class 1E power systems. The description of the power systems is presented in Section 8.3. The standby diesel generators will provide power for the operation of safety-related equipment. The station batteries will provide DC power for the operation of control and instrumentation required to actuate and control essential components.

7.4.2.3.4 Loss of Class 1E and Non-Class 1E Bus During Operation

A review of the Class 1E and Non-Class 1E busses supplying power to safety and non-safety-related instrumentation and control systems which could affect the ability to achieve cold shutdown was performed. See Section 8.3.1.2. Upon the loss of inverter output voltage (<95% of rated), an alarm is provided to alert the operator about the loss of power to the bus. A review of I&C loads concluded that a loss of power of any one instrumentation and control bus will not result in an inability to achieve cold shutdown.

TABLE 7.4-1
INSTRUMENTATION AND CONTROL LOCATED ON HOT SHUTDOWN PANEL PROVIDED FOR HOT STANDBY[a][b]

(Sheet 1 of 6)

Identification[c]	Function	
LI-501A	(d)	Steam generator 1 - level
LI-502A	(d)	Steam generator 2 - level
LI-503A		Steam generator 3 - level
LI-504A		Steam generator 4 - level
PI-514B	(d)	Steam generator 1 - pressure
PI-524B	(d)	Steam generator 2 - pressure
PI-534B		Steam generator 3 - pressure
PI-544B		Steam generator 4 - pressure
LI-459B	(d)	Pressurizer - level
LI-460B		Pressurizer - level
PI-455B	(d)	Pressurizer - pressure
LI-2478B	(d)	Condensate storage tank - level
LI-2479B		Condensate storage tank - level
HS-2450C	(d)	Motor-driven AFW pump 01 - control switch
HS-2451C		Motor-driven AFW pump 02 - control switch
HS-2451B		Motor-driven AFW pump 02 - control transfer switch
1/1-APCH1L	(d)	Charging pump 1 - control switch
1/1-APCH2L		Charging pump 2 - control switch
43/1-APCH2L		Charging pump 2 - control transfer switch
1/1-APBA1L		Boric acid transfer pump 1 - control switch
1/1-APBA2L		Boric acid transfer pump 2 - control switch

TABLE 7.4-1
INSTRUMENTATION AND CONTROL LOCATED ON HOT SHUTDOWN PANEL
PROVIDED FOR HOT STANDBY[a][b]

(Sheet 2 of 6)

Identification[c]	Function	
43/1-APBA2L		Boric acid transfer pump 2 - control transfer switch
HS-4250C	(d)	SSW pump 01 - control switch
HS-4251C		SSW pump 2 - control switch
HS-4251B		SSW pump 2 - control transfer switch
HS-4518C	(d)	CCW pump 01 - control switch
HS-4519C		CCW pump 2 - control switch
HS-4519B		CCW pump 2 - control transfer switch
43/1-456FT	(d)	Pressurizer PORV control transfer switch
1/1-456FL	(d)	Pressurizer PORV control switch
HS-2456FL	(d)	Motor-driven AFWP-1/recirculation valve control switch
HS-4286FL	(d)	SSW pump-1 discharge valve control switch
HS-4393FL	(d)	Diesel generator-1 Cooler Service Water return valve control switch
HS-4699FL		RCP/Thermal barrier cooler CCW supply isolation valve control switch
HS-4701FL		RCP motor air and lube oil coolers CCW return header isolation valve control switch
HS-4514FL	(d)	CCW heat exchanger to non-safety loop-1 isolation valve control switch
HS-4524FL	(d)	Non-safety loop return to CCW header isolation valve control switch
HS-4526FL		CCW to non-safety loop isolation valve control switch

TABLE 7.4-1
INSTRUMENTATION AND CONTROL LOCATED ON HOT SHUTDOWN PANEL
PROVIDED FOR HOT STANDBY[a][b]

(Sheet 3 of 6)

Identification[c]	Function	
1/1-8106FL	(d)	Charging pumps to Reactor Coolant System isolation valve control switch
1/1-8801AF	(d)	Charging pumps to Reactor Coolant System SIS isolation valve control switch
43/1-8153FT	(d)	Reactor Coolant system excess letdown valve control transfer switch
1/1-8153FL	(d)	Reactor Coolant system excess letdown valve control switch
1/1-8110FL	(d)	Charging pump miniflow isolation valve control switch
1/1-8701AF	(d)	RHR loop-1 inlet isolation valve control switch
1/1-8701BF	(d)(e)	RHR Loop-2 inlet isolation valve control switch
HS-2333FL	(d)	Main Steam loop-1 isolation valve control switch
HS-2334FL	(d)	Main Steam loop-2 isolation valve control switch
HS-2335FL	(d)	Main Steam loop-3 isolation valve control switch
HS-2336FL	(d)	Main Steam loop-4 isolation valve control switch
1/1-455AFL	(d)	Pressurizer power relief valve control switch
HS-6700FL	(d)	Safety Chilled water recirculation pump 5 control switch
CS-BT-1EA1L	(d)	Tie breaker BT-1EA1 control switch
CS-T1EB1L	(d)	Bus 1EA1 transformer T1EB1 feeder breaker control switch
CS-1EB1-1L	(d)	Incoming breaker 1EB1-1 control switch
CS-T1EB3L	(d)	Bus 1EA1 transformer T1EB3 feeder breaker control switch

TABLE 7.4-1
INSTRUMENTATION AND CONTROL LOCATED ON HOT SHUTDOWN PANEL
PROVIDED FOR HOT STANDBY[a][b]

(Sheet 4 of 6)

Identification[c]	Function	
CS-1EB3-1L	(d)	Incoming breaker 1EB3-1 control switch
CS-BT-1EB13L	(d)	Tie breaker BT-1EB13 control switch
TR-410F/420F/413F/423F	(d)	RCS Wide Range Temp. Cold/Hot Legs (Loops 1 & 2)
TR-430F/440F/433F/443F		RCS Wide Range Temp. Cold/Hot Legs (Loops 3 & 4)
NI-50A-3	(d)	Source Range Neutron Flux Monitoring
NI-50B-3		Source Range Neutron Flux Monitoring
1/1-8104L		Emergency Boration Valve - Control Switch
43/1-8104L		Emergency Boration Valve – Control Transfer Switch
CS-1EG1-L	(d)	Diesel Generator Breaker 1EG1 Control Switch
FK-121A	(d)	Charging Flow Control Valve (Pressurizer Level Control)
1/1-8149AL	(d)	Letdown Orifice Isolation (45 gpm) Control Switch
1/1-8149BL	(d)	Letdown Orifice Isolation (75 gpm) Control Switch
1/1-8149CL	(d)	Letdown Orifice Isolation (75 gpm) Control Switch
1/1-PCPR1L		Pressurizer Heater Backup Group A - Control Switch
1/1-PCPR2L		Pressurizer Heater Backup Group B - Control Switch
43/1-PCPR2L		Pressurizer Heater Backup Group B - control transfer switch
SK-2452B[f]		Turbine-driven AFW pump - speed controller

TABLE 7.4-1
INSTRUMENTATION AND CONTROL LOCATED ON HOT SHUTDOWN PANEL
PROVIDED FOR HOT STANDBY[a][b]

(Sheet 5 of 6)

Identification[c]	Function	
SI-2452B		Turbine-driven AFW pump - speed indication
HS-2452C	(d)	Turbine-driven AFW pump Main Steam line No. 4 supply valve - control switch
HS-2452D		Turbine-driven AFW pump Main steam line No. 1 supply valve - control transfer switch
HS-2452E		Turbine-driven AFW pump Main Steam line No. 1 supply valve - control switch
FK-2459B[f]		Turbine-driven AFW pump to steam generator 1-valve controller
FK-2453C[f]		Motor-driven AFW pump 01 to steam generator 1-valve controller
FK-2460B[f]		Turbine-driven AFW pump to steam generator 2-valve controller
FK-2453D[f]		Motor-driven AFW pump 01 to steam generator 2-valve controller
FK-2461B[f]		Turbine-driven AFW pump to steam generator 3-valve controller
FK-2454C[f]		Motor-driven AFW pump 02 to steam generator 3-valve controller
FK-2462B[f]		Turbine-driven AFW pump to steam generator 4-valve controller
FK-2454D[f]		Motor-driven AFW pump 02 to steam generator 4-valve controller
FI-121B		Charging Pump to CVCS Charging and RCP Seals - Flow
FI-2463D		AFW to steam generator 1 - flow
FI-2463B		AFW to steam generator 1 - flow
FI-2464D		AFW to steam generator 2 - flow

TABLE 7.4-1
INSTRUMENTATION AND CONTROL LOCATED ON HOT SHUTDOWN PANEL
PROVIDED FOR HOT STANDBY[a][b]

(Sheet 6 of 6)

Identification[c]	Function
FI-2464B	AFW to steam generator 2 - flow
FI-2465D	AFW to steam generator 3 - flow
FI-2465B	AFW to steam generator 3 - flow
FI-2466D	AFW to steam generator 4 - flow
FI-2466B	AFW to steam generator 4 - flow
PI-2477B	Turbine-driven AFW pump - suction pressure
PI-2455B	Turbine-driven AFW pump - discharge pressure
PI-2475B	Motor-driven AFW pump 01 - suction pressure
PI-2453B	Motor-driven AFW pump 01 - discharge pressure
PI-2476B	Motor-driven AFW pump 02 - suction pressure
PI-2454B	Motor-driven AFW pump 02 - discharge pressure
MLB-63	Train B Valve Positions

a) These instruments and controls are also provided for cold shutdown.

b) All controls in this table are provided with transfer switch

c) Where Unit 1 equipment has been identified (i.e., 1/1-APCH1L, 43/1-APCH2L, 1EA1, BT-1EA1, CS-1EG1-L) Unit 2 Identification will be similar except for prefix (i.e., 1/2..., 43/2..., CS-2..., 2EA1, BT-2...)

d) Available to accomplish the desired action for alternate shutdown during fire.

e) Valve is closed and breaker opened during normal operation to prevent fire induced spurious operation.

f) Hand/Auto station with built-in transfer device to block control room signal and initiate control room local override alarm

SSW - Station Service Water System
CCW - Component Cooling Water System
AFW - Auxiliary Feedwater System

TABLE 7.4-2
OTHER INSTRUMENTATION AND CONTROLS LOCATED ON HOT SHUTDOWN PANEL PROVIDED FOR COLD SHUTDOWN[a]

(Sheet 1 of 3)

Identification[b]	Function
FI-183B	Emergency Borate Flow
FI-132B	Letdown - Flow
1/1-TCV-129L	Letdown divert valve TCV-129 - control switch
HS-5405C	Containment recirculation fan 01 - control switch
HS-5409B	Containment recirculation fan 02 - control switch
HS-5409C	Containment recirculation fan 02 - control transfer switch
HS-5413C	Containment recirculation fan 03 - control switch
HS-5417C	Containment recirculation fan 04 - control switch
HS-5417B	Containment recirculation fan 04 - control transfer switch
FI-4258B	SSW Train A - Flow
FI-4259B	SSW Train B - Flow
PI-4252B	SSW Pump 01 - discharge pressure
PI-4253B	SSW Pump 02 - discharge pressure
V-1EA1-L	6900-V bus 1EA1 - voltage
F-1EA1-L	6900-V bus 1EA1 - frequency
A-1EA1-1L	6900-V bus 1EA1, preferred offsite source - amperes
A-1EG1-L	6900-V bus 1EA1, onsite source - amperes
A-1EA1-2L	6900-V bus 1EA1, alternate offsite source - amperes
CS-1EA1-1L	Incoming breaker 1EA1-1 - control switch
CS-1EA1-2L	Incoming breaker 1EA1-2 - control switch
V-1EA2-L	6900-V bus 1EA2 - voltage
F-1EA2-L	6900-V bus 1EA2, frequency
A-1EA2-2L	6900-V bus 1EA2, alternate offsite source - amperes
A-1EG2-L	6900-V bus 1EA2, onsite source - amperes

TABLE 7.4-2
OTHER INSTRUMENTATION AND CONTROLS LOCATED ON HOT SHUTDOWN PANEL PROVIDED FOR COLD SHUTDOWN[a]

(Sheet 2 of 3)

Identification[b]	Function
A-1EA2-1L	6900-V bus 1EA2, preferred offsite source - amperes
CS-1EA2-2L	Incoming breaker 1EA2-2 - control switch
CS-1EG2-L	Diesel Generator 2 breaker 1EG2 - control switch
CS-1EA2-1L	Incoming breaker 1EA2-1 - control switch
43-1EA2-2	Breaker 1EA2-2 control transfer switch
43-1EG2	Diesel Generator 2 breaker 1EG2 control transfer switch
43-1EA2-1	Breaker 1EA2-1 control transfer switch
ZL-2476B	Motor-driven AFWP-2 suction pressure status light
ZL-2454C	Motor-driven AFWP-2 discharge to SG-3 control valve position
ZL-2454D	Motor-driven AFWP-2 discharge to SG-4 control valve position
ZL-2459B	Turbine-driven AFWP discharge to SG-1 control valve position
ZL-2460B	Turbine-driven AFWP discharge to SG-2 control valve position
ZL-2453C	Motor-driven AFWP-1 discharge to SG-1 control valve position
ZL-2475B	Motor-driven AFWP-1 suction pressure status light
ZL-2453D	Motor-driven AFWP-1 discharge to SG-2 control valve position
ZL-2461B	Turbine-driven AFWP discharge to SG-3 control valve position
ZL-2462B	Turbine-driven AFWP discharge to SG-4 control vavle position
ZL-455CF	Pressurizer spray valve position

TABLE 7.4-2
OTHER INSTRUMENTATION AND CONTROLS LOCATED ON HOT SHUTDOWN PANEL PROVIDED FOR COLD SHUTDOWN[a]

(Sheet 3 of 3)

Identification[b]	Function	
ZL-455BF		Pressurizer spray valve position
ZL-PCPX1F		RCP-1 running
ZL-PCPX2F		RCP-2 running
ZL-PCPX3F		RCP-3 running
ZL-PCPX4F		RCP-4 running
HS-5180F		Steam generator heat exchanger outlet pressure control switch
HC-2325		SG-1 atmospheric relief valve control
HC-2326		SG-2 atmospheric relief valve control
HC-2327		SG-3 atmospheric relief valve control
HC-2328		SG-4 atmospheric relief valve control
HC-455C		RC Loop 4 pressurizer spray valve control
HC-606A	(c)	RHR Heat Exchanger Flow Control
HC-618	(c)	RHR Heat Exchanger Bypass Flow Control
1/1-APRH1F	(c)	RHR pump 1 control switch

a) The items in Table 7.4-1 are also provided for cold shutdown

b) Where Unit 1 equipment has been identified (i.e., 1/1-TCV-129L, 1EA1, V-1EA1-L) Unit 2 identification will be similar except for prefix (i.e., 1/2..., V-2..., 2EA1).

c) Available to accomplish the desired action for alternate shutdown during fire

SSW - Station Service Water System
CCW - Component Cooling Water System
AFW - Auxiliary Feedwater System

TABLE 7.4-3
TRANSFER SWITCHES LOCATED ON SHUTDOWN TRANSFER PANEL (STP)

(Sheet 1 of 3)

Identification[a]	Function	
HS-2450B	(b)	Motor-driven AFWP-1 remote local
HS-2453AF	(b)	Motor-driven AFWP-1 SG-1 flow control valve remote local
HS-2453BF	(b)	Motor-driven AFWP-1 to SG-2 control valve remote local
HS-2456FT	(b)	Motor-driven AFWP-1 recirculation valve remote local
43/1-121-FT	(b)	Charging flow control remote local
HS-4250B	(b)	SSW pump-1 remote local
HS-4286FT	(b)	SSW pump-1 discharge valve remote local
HS-4393FT	(b)	Diesel generator-1 SSW return valve remote local
HS-4699FT		RCP/Thermal Barrier Cooler CCW supply Isolation valve remote local
HS-4701FT		RCP cooler CCW return isolation remote local
HS-4518B	(b)	CCW pump-1 remote local
HS-4514FT	(b)	Safeguard Loop CCW supply isolation remote local
HS-4524FT	(b)	Non-Safeguard Loop CCW Return valve remote local
HS-4526FT	(b)	Non-Safeguard Loop CCW Supply Valve remote control
HS-5405B		Containment recirculation fan 01 remote local
43/1-APCH1L	(b)	Centrifugal charging pump-1 remote local
43/1-APBA1L		Boric acid transfer pump-1 remote local
HS-5413B		Containment recirculation fan 03 remote local

TABLE 7.4-3
TRANSFER SWITCHES LOCATED ON SHUTDOWN TRANSFER PANEL (STP)

(Sheet 2 of 3)

Identification[a]	Function	
43/1-8106FT	(b)	Charging pumps to Reactor Coolant System isolation valve remote local
43/1-8801AF	(b)	Charging pumps to Reactor Coolant System SIS isolation valve remote local
43/1-8149AL	(b)	CVCS letdown orifice isolation valve remote local
43/1-8149BL	(b)	CVCS letdown orifice isolation valve remote local
43/1-8149CL	(b)	CVCS letdown orifice isolation valve remote local
43/1-8110FT	(b)	Charging pump miniflow isolation valve remote local
43/1-APRH1F	(b)	RHR pump-1 remote local
43/1-8701AF	(b)	RHRP 1 Hot Leg Recirculation Isolation
43/1-8701BF	(b)(c)	RHRP 2 Hot Leg Recirculation Isolation
HS-2452B	(b)	Turbine-driven AFWP steam supply line 4 valve remote local
43/1-TCV-129		Letdown to demineralizer or volume control tank remote local
HS-2333FT	(b)	Main Steam loop 1 isolation valve remote local
HS-2334FT	(b)	Main Steam loop 2 isolation valve remote local
HS-2335FT	(b)	Main Steam loop 3 isolation valve remote local
HS-2336FT	(b)	Main Steam loop 4 isolation valve remote local
43/1-455AFT	(b)	Pressurizer power relief valve remote local
43/1-PCPR1L		Pressurizer heater backup group-A remote local

TABLE 7.4-3
TRANSFER SWITCHES LOCATED ON SHUTDOWN TRANSFER PANEL (STP)

(Sheet 3 of 3)

Identification[a]	Function	
HS-6710B	(b)	Safety Chill Water Chiller Bypass Lockout
HS-67OOFT	(b)	Chilled water recirculation pump-5 remote local
43/1EA1-1	(b)	Incoming breaker 1EA1-1 remote local
43/1EA1-2	(b)	Incoming breaker 1EA1-2 remote local
43/1EG1	(b)	Diesel generator breaker 1EG1 remote local
43/BT-1EA1	(b)	Tie breaker BT-1EA1 remote local
43/T1EB1	(b)	Bus 1EA1 transfer T1EB1 feeder breaker remote local
43/1EB1-1	(b)	Incoming breaker 1EB1-1 remote local
43/T1EB3	(b)	Bus 1EA1 transfer 1EB3 feeder breaker remote local
43/1EB3-1	(b)	Incoming breaker 1EB3-1 remote local
43/BT-1EB13		Tie breaker BT-1EB13 remote local

a) Where Unit 1 equipment has been identified (i.e., 43/1-121-/ft, 1EA1) Unit 2 Identification will be similar except for prefix (i.e., 43/2..., 2EA1-1, BT-2...).

b) Available to accomplish the desired action for alternate shutdown during fire.

c) Valve is closed and breaker opened during normal operation to prevent fire induced spurious operation.

SSW - Station Service Water System
CCW - Component Cooling Water System
AFW - Auxiliary Feedwater System

7.5 INFORMATION SYSTEMS IMPORTANT TO SAFETY

7.5.1 DESCRIPTION OF INFORMATION SYSTEMS

The plant safety analyses and evaluations define the design basis accident event scenarios for which pre-planned operator actions are required. Accident monitoring instrumentation is necessary to permit the operator to take required actions to address these analyzed situations. However, instrumentation is also necessary for unforeseen situations (i.e., to ensure that, should plant conditions evolve differently than predicted by the safety analyses, the control room staff has sufficient information to monitor the course of the event). Additional instrumentation is also needed to indicate to the operator whether the integrity of the in-core fuel clad, the reactor coolant system pressure boundary, or the reactor containment has degraded beyond the prescribed limits defined as a result of the plant safety analyses and other evaluations.

Five classifications of variables have been identified to provide this instrumentation. These five classification supercede the “PAMS” classification previously required by U.S. NRC Regulatory Guide 1.97, Revision 1. Operator manual actions identified in the emergency response procedures, associated with design basis accident events are pre-planned. Those variables that provide information needed by the operator to perform these manual actions are designated Type A. The basis for selecting Type A variables is given in Section 7.5.1.2.1.

Those variables needed to assess that the plant critical safety functions are being accomplished or maintained, as identified in the plant safety analysis and other evaluations, are designated Type B.

Variables used to monitor for the gross breach or the potential for gross breach of the in-core fuel clad, the reactor coolant system pressure boundary, or the primary reactor containment, are designated Type C. Variables used to monitor the potential breach of containment have an arbitrarily determined extended range. The extended range is chosen to minimize the probability of instrument saturation even if conditions exceed those predicted by the safety analysis. The response characteristics of Type C information display channels allows the control room staff to detect conditions indicative of gross failure of any of the three fission product barriers or the potential for gross failure of these barriers. Although variables selected to fulfill Type C functions may rapidly approach the values that indicate an actual gross failure, it is the final steady-state value reached that is important. Therefore, a high degree of accuracy and a rapid response time are not necessary for Type C information display channels.

Those variables needed to assess the operation of individual safety systems and other systems important to safety are designated Type D.

The variables that are required for use in determining the magnitude of the postulated releases and continually assessing any such releases of radioactive materials are designated Type E.

The five classifications are not mutually exclusive, in that, a given variable (or instrument) may be included in one or more types. When a variable is included in one or more of the five classifications, the equipment monitoring this variable will meet the highest category as noted in Tables 7.5-7A, B & C.

Three categories of design and qualification criteria have been identified. The differentiation is made in order that an importance of information hierarchy can be recognized in specifying

accident monitoring instrumentation. Category 1 instrumentation has the highest pedigree and should be utilized for information which is essential to the control room operating staff in order for them to determine if the plant safety functions are being performed. Category 2 and Category 3 instruments are of lesser importance in determining the state of the plant and do not require the same level of operational assurance.

Category 1 displays located on the Main Control Boards will be uniquely identified.

The primary differences between category requirements are in qualification, application of single failure, power supply, and display requirements. Category 1 requires seismic and environmental qualification, the application of a single failure criteria, utilization of emergency standby power, and a continuous display. Category 2 requires qualification commensurate with the required function but does not require the single failure criteria, emergency standby power, or a continuous display. Category 2 requires, in effect, a rigorous performance verification for a single instrument channel. Category 3 does not require qualification, single failure criteria, emergency standby power, or a continuous display.

7.5.1.1 Definitions

7.5.1.1.1 Design Basis Accident Events

Those events, any one of which could occur during the lifetime of a particular unit and those events not expected to occur but postulated because their consequences would include the potential for release of significant amounts of radioactive gaseous, liquid, or particulate material to the environment are Design Basis Accident Events. Excluded are those events (defined as “normal” and “anticipated operational occurrences” in 10 CFR 50) expected to occur more frequently than once during the lifetime of a particular unit. The limiting accidents that are used to determine instrument functions are: 1) LOCA, 2) Steamline Break, 3) Feedwater Line Break, and 4) Steam Generator Tube Rupture.

7.5.1.1.2 Safe Shutdown

The safe shutdown condition is completely defined in CPNPP/FSAR Section 7.4.

7.5.1.1.3 Deleted

7.5.1.1.4 Critical Safety Functions

Those safety functions that are essential to prevent a direct and immediate threat to the health and safety of the public. These are the accomplishing or maintaining of:

1. Subcriticality (reactivity control)

2. Reactor coolant system integrity

3. Reactor coolant system inventory

4. Reactor core cooling

5. Heat sink

6. Containment integrity

7.5.1.1.5 Immediately Accessible Information

Information that is visually available to the control room operator immediately after he has made the decision that the information is needed.

7.5.1.1.6 Primary Information

Information that is essential for the direct accomplishment of the pre-planned manual actions necessary to bring the plant into a safe condition in the event of a Design Basis Accident Event; it does not include those variables that are associated with contingency actions.

7.5.1.1.7 Contingency Actions

Those manual actions that address conditions beyond the Design Basis Accident Events.

7.5.1.1.8 Key Variables

Those variables which provide the most direct measure of the information required.

7.5.1.1.9 Preferred Backup Variables

Those backup variables that provide the most direct information for the key variable being monitored.

7.5.1.1.10 Backup Variable

That information, made up of additional variables, that provides supplemental and/or confirmatory information to the Control Room Operating Staff.

7.5.1.1.11 Diverse Variable

Where failure of an accident monitoring channel results in information ambiguity that can lead the operator to defeat or fail to accomplish a required safety function, a second variable shall be identified to allow the operator to deduce the actual conditions of the plant. This second variable is called a diverse variable.

7.5.1.2 Variable Types

The accident monitoring variables and information display channels are those that are required to enable the Control Room Operating Staff to perform the functions defined by Types A, B, C, D, and E below.

7.5.1.2.1 Type A

Those variables that provide the primary information required to permit the Control Room Operating Staff to:

1. Perform the diagnosis specified in the applicable CPNPP Emergency Response Guidelines (ERG),

2. Take the specified pre-planned manually controlled actions, for which no automatic control is provided, that are required for safety systems to accomplish their safety function in order to recover from the Design Basis Accident Event, and

3. Reach and maintain a safe shutdown condition.

Consistent with the definition of Type A variables in Regulatory Guide 1.97 Revision 2, the verification of the actuation of safety systems has been excluded from the definition of Type A. The variables which provide this verification are included in the definition of Type D.

Variables in Type A are restricted to pre-planned actions for Design Basis Accident Events. Contingency actions and additional variables which might be utilized will be in Types B, C, D, and E.

7.5.1.2.2 Type B

Those variables that provide to the Control Room operating staff information to assess the process of accomplishing or maintaining critical safety functions, i.e., reactivity control, reactor coolant system integrity, RCS inventory, reactor core cooling, heat sink, and containment integrity.

7.5.1.2.3 Type C

Those variables that provide to the Control Room Operating Staff information to monitor (1) the extent to which variables, which indicate the potential for causing a gross breach of a fission product barrier, have exceeded the design basis values and (2) that the in-core fuel cladding, the reactor coolant system pressure boundary or the primary reactor containment may have been subject to gross breach. These variables include those required to initiate the early phases of the emergency plan.

Type C variables used to monitor the potential for breach of a fission product barrier have an arbitrarily-determined extended range.

7.5.1.2.4 Type D

Those variables that provide to the control room operating staff sufficient information to monitor the performance of:

1. plant safety systems employed for mitigating the consequences of an accident and subsequent plant recovery to attain a safe shutdown condition. These include verification of the automatic actuation of safety systems, and

2. other systems normally employed for attaining a safe shutdown condition.

7.5.1.2.5 Type E

Those variables to be monitored as required for use in determining accessibility for required post accident actions, estimating the potential magnitude of the release of radioactive materials, and continually assessing such releases.

7.5.1.3 Variable Categories

The qualification requirements of the Type A, B, C, D and E accident monitoring instrumentation are subdivided into three categories (1, 2, 3). Descriptions of the three categories are given below. Table 7.5-1 briefly summarizes the design and qualification requirements of the three designated categories.

7.5.1.3.1 Category 1

7.5.1.3.1.1 Selection Criteria for Category 1

The selection criteria for Category 1 variables have been subdivided according to the variable type. For Type A, those key variables used for diagnosis or providing information for preplanned operator action have been designated Category 1. For Type B, those key variables which are used for monitoring the process of accomplishing or maintaining critical safety functions have been designated Category 1. For Type C, those key variables which are used for monitoring the potential for breach of a fission product barrier have been designated Category 1.

7.5.1.3.1.2 Qualification Criteria for Category 1

The instrumentation is environmentally and seismically qualified in accordance with Sections 3.11 and 3.10, respectively, of the FSAR. Instrumentation shall continue to read within the required accuracy following but not necessarily during a seismic event. At least one redundant instrumentation channel for each Category 1 variable is qualified from sensor to a direct-indicating meter or recording device. For the balance of instrumentation channels, qualification applies up to and includes the channel isolation device. (Refer to Section 7.5.1.3.4 in regard to extended range instrumentation qualification).

7.5.1.3.1.3 Design Criteria for Category 1

1. No single failure within either the accident-monitoring instrumentation, its auxiliary supporting features, or its power sources, concurrent with the failures that are a condition of or result from a specific accident, will prevent the operator from being presented the required information. Where failure of one accident-monitoring channel results in information ambiguity (e.g., the redundant displays disagree), additional information is provided to allow the operator to deduce the actual conditions in the plant. This may be accomplished by providing additional independent channels of information of the same variable (addition of an identical channel), or by providing independent channels which monitor different variables which bear known relationships to the multiple channels (addition of a diverse channel(s)). Redundant or diverse channels are electrically independent and physically separated from each other to the extent practicable with two train separation, and from equipment not classified important to safety in accordance with 10 CFR 50 Appendix A, Criteria 22 and 24, and derived regulatory guides consistent with the licensing basis for CPNPP. See FSAR Sections 1A(N) and 1A(B).

When diversity is employed in lieu of redundancy, detailed procedures will be established to detect and resolve any ambiguity that may exist. These procedures recognizes such factors as electrical independence and physical separation of the channels employed.

2. The instrumentation is energized from station emergency standby power sources, battery backed where momentary interruption is not tolerable.

3. The out-of-service interval is based on normal Technical Specification requirements for the system it serves where applicable or where specified by other requirements.

4. Servicing, testing, and calibration programs are specified to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing is less than the normal time interval between generating station shutdowns, a capability for testing during power operation is provided.

5. Whenever means for removing channels from service are included in the design, the design facilitates administrative control of the access to such removal means.

6. The design facilitates administrative control of the access to all setpoint adjustments, module calibration adjustments, and test points.

7. The monitoring instrumentation design minimizes the development of conditions that would cause meters, annunciators, recorders, alarms, etc., to give anomalous indications potentially confusing to the operator.

8. The instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

9. To the extent practicable, monitoring instrumentation inputs will be from sensors that directly measure the desired variables.

10. Periodic checking, testing, calibration, and calibration verification is in accordance with the CPNPP Technical Specification as implemented by CPNPP procedures. When no CPNPP Technical Specifications are applicable, CPNPP plant specific procedures are implemented.

7.5.1.3.1.4 Information Processing and Display Interface Criteria for Category 1

The interface criteria specified here provide requirements to be implemented in the processing and displaying of the information.

1. The operator has immediate access to the information from redundant or diverse channels in units familiar to the operator (i.e., for temperature readings degrees should be used, not volts). Where two or more instruments are needed to cover a particular range, overlapping of instrument spans are provided.

2. A historical record of a minimum of one instrumentation channel for each process variable is maintained. The ERF computer system has the capacity to handle the two hour pre-event and twelve hour post-event archival storage requirement at normal expected

frequency of data acquisition. In addition graphs of critical parameters during any immediately preceding thirty minute period will be available.

7.5.1.3.2 Category 2

7.5.1.3.2.1 Selection Criteria for Category 2

The selection criteria for Category 2 variables are subdivided according to the variable type. For Types B and C those variables which provide preferred backup information are designated Category 2. For types D, and E, (except the Containment Radiation Level (High Range) which is designated category 1) key variables have been included under Category 2.

7.5.1.3.2.2 Qualification Criteria for Category 2

Category 2 instrumentation is environmentally qualified when it is subjected to adverse environments caused by the DBA during the time it must serve its intended function. Category 2 instrumentation is seismically qualified from the sensor up to and including the channel isolation device when the instrument is a part of a safety related system and its failure could degrade the system (e.g., the channel is Class 1E).

7.5.1.3.2.3 Design Criteria for Category 2

1. The instrumentation is energized from a highly reliable on-site power source, not necessarily the emergency standby power, which is battery backed where momentary interruption is not tolerable.

2. The out-of-service interval is based on normal Technical Specification requirements for the system it serves where applicable or where specified by other requirements.

3. Servicing, testing, and calibration programs are specified to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing is less than the normal time interval between generating station shutdowns, a capability for testing during power operation is provided.

4. Whenever means for removing channels from service are included in the design, the design facilitates administrative control of the access to such removal means.

5. The design facilitates administrative control of the access to all setpoint adjustments, module calibration adjustments, and test points.

6. The monitoring instrumentation design minimizes the development of conditions that would cause meters, annunciators, recorders, alarms, etc., to give anomalous indications potentially confusing to the operator.

7. The instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

8. To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables.

9. Periodic checking, testing, calibration, and calibration verification is in accordance with CPNPP plant specific procedures.

7.5.1.3.2.4 Information Processing and Display, Interface Criteria for Category 2

The instrumentation signal is, as a minimum, processed for display on demand. See Section 7.5.1.3.1.4 Item 2.

7.5.1.3.3 Category 3

7.5.1.3.3.1 Selection Criteria for Category 3

For all types, those variables which provide backup information are designated Category 3.

7.5.1.3.3.2 Qualification Criteria for Category 3

The instrumentation is high quality commercial grade, selected to withstand its' service environment.

7.5.1.3.3.3 Design Criteria for Category 3

1. Servicing, testing, and calibration programs are specified to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing is less than the normal time interval between generating station shutdowns, a capability for testing during power operation is provided.

2. Whenever means for removing channels from service are included in the design, the design facilitates administrative control of the access to such removal means.

3. The design facilitates administrative control of the access to all setpoint adjustments, module calibration adjustments, and test points.

4. The monitoring instrumentation design minimizes the development of conditions that would cause meters, annunciators, recorders, alarms, etc., to give anomalous indications potentially confusing to the operator.

5. The instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

6. To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables.

7. The instrumentation signal is, as a minimum, processed for display on demand. See Section 7.5.1.3.1.4 Item 2.

7.5.1.3.3.4 Extended Range Instrumentation Qualification Criteria

The qualification environment for extended range information display channel components is based on the Design Basis Accident Events, except the assumed maximum value of the monitored variable shall be the value equal to the specified maximum range for the variable. The

decay for this variable is considered proportional to the decay for this variable associated with the Design Basis Accident Events. No additional qualification margin needs to be added to the extended range variable. All environmental envelopes except that pertaining to the variable measured by the information display channel will be those associated with the Design Basis Accident Events. The environmental qualification requirement for extended range equipment does not account for steady-state elevated levels that may occur in other environmental parameters associated with the extended range variable. For example, a sensor measuring containment pressure must be qualified for the measured process variable range (i.e., 3 times design pressure for concrete containments), but the corresponding ambient temperature is not mechanistically linked to that pressure. Rather, the ambient temperature value is the bounding value for Design Basis Accident Events analyzed in Chapter 15 of the FSAR. The extended range requirement is to ensure that the equipment will continue to provide information if conditions degrade beyond those postulated in the safety analysis. Since extended variable ranges are non-mechanistically determined, as in the example of containment pressure and ambient temperature, extension of associated parameter levels is not justifiable and is therefore not required.

7.5.2 DESCRIPTION OF VARIABLES

7.5.2.1 Type A Variables

Type A variables are defined in Section 7.5.1.2.1. They are the variables which provide primary information required to permit the Control Room operating staff to:

1. Perform the diagnosis specified in the applicable CPNPP ERG's;

2. Take specified pre-planned manually controlled actions for which no automatic control is provided, that are required for safety systems to accomplish their safety function to recover from the Design Basis Accident Event (verification of actuation of safety systems is excluded from Type A variables and is included as Type D);

3. Reach and maintain a safe shutdown condition.

Key Type A variables have been designated Category 1. These are the variables which provide the most direct measure of the information required. The KEY Type A variables are:

1. RCS Wide Range Pressure

2. Wide Range Hot Leg Reactor Coolant Temperature (T(Hot))

3. Wide Range Cold Leg Reactor Coolant Temperature (T(Cold))

4. RCS Subcooling (Saturation Margin)

5. Narrow Range Steam Generator Water Level (NR)

6. Pressurizer Water Level

7. Containment Pressure - Intermediate range

8. Main Steam Line Pressure (S/G Pressure)

9. Refueling Water Storage Tank (RWST) Level

10. Deleted

11. Condensate Storage Tank (CST) Level

12. Auxiliary Feedwater (AFW) Flow to each S/G

13. Core Exit Temperature

All Type A Variables have been designated Category 1.

A summary of Type A Variables is provided in Table 7.5-2.

7.5.2.2 Type B Variables

Type B variables are defined in Section 7.5.1.2.2. They are the variables that provide to the Control Room Operating Staff information to assess the process of accomplishing or maintaining critical safety functions, i.e.:

1. Subcriticality (Reactivity Control)

2. Reactor Coolant System integrity

3. Reactor Coolant System Inventory

4. Reactor Core Cooling

5. Heat Sink

6. Containment integrity

Variables which provide the most direct indication (i.e., Key variable) to assess each of the critical safety functions have been designated Category 1. Preferred backup variables have been designated Category 2. All other backup variables are Category 3. These are listed in Table 7.5-3.

7.5.2.3 Type C Variables

Type C variables are defined in Section 7.5.1.2.3. Basically, they are the variables that provide to the Control Room Operating Staff information to monitor the potential for breach or actual gross breach of:

1. In-core fuel clad;

2. Reactor Coolant System Boundary;

3. Containment Boundary.

(Variables associated with monitoring of radiological releases from the plant are included in Type E).

Those Type C key variables which provide the most direct measure of the POTENTIAL for breach of one of the 3 fission product boundaries have been designated Category 1. Variables which indicate actual breach have been designated as preferred backup information and are designated Category 2. All other backup variables are designated Category 3.

Table 7.5-4 summarizes the selection of Type C variables.

7.5.2.4 Type D Variables

Type D variables are defined in Section 7.5.1.2.4. They are those variables that provide sufficient information to the Control Room Operating Staff to monitor the performance of:

1. Plant safety systems employed for mitigating the consequences of an accident and subsequent plant recovery to attain a safe shutdown condition, including verification of the automatic actuation of safety systems; and

2. Other systems normally employed for attaining a safe shutdown condition.

Type D key variables are designated Category 2. Backup variables are designated Category 3.

The following systems or major components have been identified as requiring Type D variables to be monitored:

1. Reactor Coolant Pump (to assure RCS pressure boundary integrity by maintaining seal integrity)

2. Pressurizer level and pressure control to assess status of RCS following return to normal pressure and level control under certain post-accident conditions

3. Chemical and Volume Control System (CVCS) (employed for attaining a safe shutdown under certain post-accident conditions)

4. Main Steam and Feedwater Systems (employed for restoring/maintaining a secondary heat sink under post-accident conditions)

5. Emergency Core Cooling System (ECCS)

6. Auxiliary Feedwater

7. Containment Systems

8. Component Cooling Water

9. Service Water

10. Heating, Ventilation, Air Conditioning (HVAC) if required for ESF operation

11. Safety Chilled Water

12. Vital Electrical Power Supplies

13. Residual Heat Removal

14. Radioactive Waste System

Table 7.5-5 summarizes the selection of Type D variables.

7.5.2.5 Type E Variables

Type E variables are defined in Section 7.5.1.2.5. They are those variables that provide the Control Room operating staff with information to:

1. Monitor the habitability in the control room,

2. Monitor the plant areas where access may be required to service equipment necessary to monitor or mitigate the consequences of an accident and the post accident radiation environment warrants continuous monitoring,

3. Estimate the magnitude of the radiation source available for potential release,

4. Estimate the magnitude of release of radioactive materials through identified pathways, and

5. Estimate the magnitude of unplanned releases of radioactive material from unidentified pathways.

Containment Radiation Level has been designated Category 1. All other Key Type E variables have been designated Category 2. Backup Type E variables have been designated Category 3.

Table 7.5-6 summarizes the selection of Type E variables.

7.5.3 ANALYSIS OF INFORMATION SYSTEMS IMPORTANT TO SAFETY

7.5.3.1 Compliance With General Design Criteria 2

All Category 1 instrumentation and that Category 2 instrumentation which is part of a safety related system and whose failure could degrade the system are seismically qualified as noted in Tables 7.5-7A, B & C. See CPNPP FSAR Section 3.10.

7.5.3.2 Compliance With General Design Criteria 4

All Category 1 instrumentation and that Category 2 instrumentation which is subjected to adverse environments when it must perform its intended function are environmentally qualified as noted in Tables 7.5-7A, B & C. See CPNPP FSAR Section 3.11.

7.5.3.3 Compliance With General Design Criteria 13

The instrumentation identified in CPNPP FSAR Tables 7.5-7A, B & C monitors the proper variables over adequate ranges to assure adequate safety.

7.5.3.4 Compliance With General Design Criteria 19

The instrumentation provided allows for safe operation of the plant from the control room and allows the maintenance of a safe condition under design basis accident conditions. Adequate instrumentation is also provided outside the control room to allow for safe shutdown and cold shutdown (see CPNPP FSAR Section 7.4).

7.5.3.5 Compliance With U.S. NRC Regulatory Guide 1.47

The bypassed and inoperable status system (Safety System Inoperable Indication (SSII) are described in Section 7.1.2.6 under a discussion of conformance to U.S. NRC Regulatory Guide 1.47. The SSII is in accordance with the Regulatory Guide as described in the referenced section. Also, see Figure 7.1-4 for typical implementation of SSII for an ESF System.

7.5.3.6 Compliance With U.S. NRC Regulatory Guide 1.97

As described throughout CPNPP FSAR Section 7.5, CPNPP meets the intent of U.S. NRC Regulatory Guide 1.97.

Table 7.5-7A provides information on instrument range, environmental/seismic qualification, quality assurance, redundance and sensor location and the power supply for the variables listed in Table 2 to the Regulatory Guide 1.97, Rev. 2. Table 7.5-7B provides similar information pertaining to those variables included in the CPNPP accident monitoring design which are not listed in Table 2 to Regulatory Guide 1.97, Rev. 2.

Table 7.5-7C pertains to the notes to Tables 7.5-7A and 7.5-7B. Table 7.5-7D lists specific deviations which did not meet or exceed the guidance of the Regulatory Guide as identified in Table 7.5-7A. Table 7.5-7E includes the supporting justifications and alternatives that correspond to each of the deviations listed and reference numbers in Table 7.5-7D. Table 7.5-7F includes general deviations from the Regulatory Guide and provides the defferences between the specific wording of Section C in the Regulatory GUide and CPNPP design along with any justifications.

7.5.3.7 Compliance With U.S. NRC Regulatory Guide 1.105

The accuracies and ranges of the instruments selected to monitor the variables specified are consistent with the assumptions used in the accident analysis. See FSAR Section 1A(N) and 1A(B).

7.5.3.8 Other Information Systems and Human Factors Evaluations

Other information systems such as the safety parameter display system and the ERF (emergency response facility) data display systems (see FSAR Section III.A.1.2) are integrated with the CPNPP instrumentation described in this section. In order to provide the operator adequate information to prevent and cope with accidents, these displays have been included in human factors engineering reviews as discussed in CPNPP FSAR Section I.D.1.

Monitor light displays consist of two independent trains of status monitoring equipment, one for each safety train. The displays, located on the Control Board in the vicinity of the ESF system controls, are light box arrays which monitor the status of ESF support system valves, dampers, pumps, and fans. The displays provide visual indication that the components are not in their correct position, in the case of valves and dampers, or in their correct operational mode in the case of pumps and fans, following receipt of a safety actuation signal. The monitor light displays provide a convenient overview of the ESF functions and main control board indication for some of the accident monitoring instrumentation. These light displays are qualified seismic Class 1E. See Sections 7.5, 7.5.3.6, Tables 7.5-7A, B, C, D, E, and F.

TABLE 7.5-1
SUMMARY OF MINIMUM DESIGN QUALIFICATION, AND INTERFACE REQUIREMENTS

Qualification	Category 1	Category 2	Category 3
Enviromental	Yes	As appropriate	No
Seismic	Yes	As appropriate	No
Design			
Single Failure	Yes	No	No
Power Supply	Emergency Standby	Highly Reliable (On-Site)	Non-1E
Interface			
Indication	Immediately Accessible	On Demand	On Demand
Recording	ERF Computer	No	No

TABLE 7.5-2
SUMMARY OF TYPE A VARIABLES

Variable	Variable Function	Type/ Category
RCS Pressure (WR)	Key	A1
T(HOT) (WR)	Key	A1
T(COLD) (WR)	Key	A1
RCS Subcooling Water	Key	A1
Steam Generator Water Level (NR)	Key	A1
Pressurizer Level	Key	A1
Containment Pressure (IR)	Key	A1
Main Steam Line Pressure (S/G Pressure)	Key	A1
RWST Level	Key	A1
CST Level	Key	A1
Auxiliary Feedwater Flow to each S/G	Key	A1
Core Exit Temperature	Key	A1

WR - Wide Range NR - Narrow Range IR - Intermediate Range

TABLE 7.5-3
SUMMARY OF TYPE B VARIABLES

(Sheet 1 of 2)

Function Monitored	Variable	Variable Function	Type/ Category
Subcriticality	Neutron Flux	KeyB1	
Reactivity	Wide Range T(Hot)	Backup (P)	B2
Control	Wide Range T(Cold)	Backup (P)	B2
	Control Rod Position	Backup	B3
Reactor	RCS Pressure (WR)	Key	B1
Coolant	Wide Range T (Hot)	Key	B1
System	Wide Range T (Cold)	Key	B1
Integrity	Core Exit Temperature	Key	B1
	Containment Radiation Level	Backup (P)	B2
	Condenser Off-gas Radiation	Backup (P)	B2
	S/G Blowdown Radiation Level	Backup (P)	B2
	Containment Water Level	Backup (P)	B2
Reactor	Pressurizer Level	Key	B1
Coolant	Reactor Vessel Water	Key	B1
System	Level (RVLIS)		
Inventory	Containment Water Level	Backup (P)	B2
Reactor	Core Exit Temperature	Key	B1
Core	RCS Subcooling	Key	B1
Cooling	Reactor Vessel Water	Key	B1
	Level (RVLIS)		
	Wide Range T (Hot)	Backup (P)	B2
	Wide Range T (Cold)	Backup (P)	B2
	RCS Pressure (WR)	Backup (P)	B2

TABLE 7.5-3
SUMMARY OF TYPE B VARIABLES

(Sheet 2 of 2)

Function Monitored	Variable	Variable Function	Type/ Category
Heat Sink	Steam Generator Level (NR)	Key	B1
	Steam Generator Level (WR)	Key	B1
	Auxiliary Feedwater Flow to each S/G	Key	B1
	Main Steamline Pressure (S/G Pressure)	Key	B1
Containment Integrity	Containment Pressure (IR)	Key	B1
	Containment Water Level	Key	B1
	Containment Hydrogen Concentration	Backup	B3

Backup (P) - Preferred backup

IR - Intermediate Range

TABLE 7.5-4
SUMMARY OF TYPE C VARIABLES

Function Monitored	Variable	Variable Function	Type/ Category
Fuel Cladding	Core Exit Temperature	Key	C1
	Reactor Vessel Water Level (RVLIS)	Backup (P)	C2
RCS Pressure Boundary	RCS Pressure (WR)	Key	C1
	Containment Pressure (IR)	Backup (P)	C2
	Containment Water Level	Backup (P)	C2
	Containment Radiation Level (HR)	Backup (P)	C2
	S/G Blowdown Radiation Level	Backup (P)	C2
	Condenser Off-gas Radiation	Backup (P)	C2
Containment Boundary	Containment Pressure (WR)	Key	C1
	Containment Hydrogen Concentration	Backup	C3
	Plant Vent Effluent radioactivity and flow	Backup (P)	C2
	RCS Pressure (WR)	Backup (P)	C2
	Containment Isolation Valve Status[(a)]	Backup (P)	C2
	Containment Pressure (IR)	Backup (P)	C2
	Area Radiation Level Adjacent Containment	Backup (P)	C3

a) Excludes local manual, check, relief and safety valves.

IR - Intermediate Range
WR - Wide Range
HR - High Range

TABLE 7.5-5
TYPE D - VARIABLES

(Sheet 1 of 6)

System/Component	Variable	Variable Function	Type/ Category
Reactor Coolant Pump	CCW to RCP Valve Status	Key	D2
	RCP Seal Injection Isolation Valve Status	Key	D2
	Motor Current	Backup	D3
	Seal Injection Flow	Backup	D3
Pressurizer Level and Pressure Control	PORV Valve Status	Key	D2
	Pressurizer PORV Block Valve Status	Key	D2
	Safety Valve Status	Key	D2
	Pressurizer Level	Key	D2
	RCS Pressure (WR)	Key	D2
	Heater Current	Key	D2
	Pressurizer Relief Tank Level	Backup	D3
	Pressurizer Relief Tank Temperature	Backup	D3
	Pressurizer Relief Tank Pressure	Backup	D3
Chemical and Volume Control System (CVCS)	Charging system makeup flow	Key	D2
	Letdown flow	Key	D2
	VCT level	Key	D2
	CVCS valve status	Key	D2
	Boric Acid Tank Level	Key	D2

TABLE 7.5-5
TYPE D - VARIABLES

(Sheet 2 of 6)

System/Component	Variable	Variable Function	Type/ Category
Main Steam and Feedwater Systems	S/G PORV status	Key	D2
	MSIV and bypass Valve status	Key	D2
	S/G safety valve status	Key	D2
	S/G blowdown isolation valve status	Key	D2
	S/G Sampling isolation valve status	Key	D2
	AFW Pump Turbine Main Steam Header Isolation Valve status	Key	D2
	CST water level	Key	D2
	Main Steamline pressure (S/G Pressure)	Key	D2
	Auxiliary Feedwater flow to each S/G	Key	D2
	S/G water level (WR)	Key	D2
	S/G water level (NR)	Key	D2
	MFW control and bypass valve status	Key	D2
	MFW isolation and bypass valve status	Key	D2
	MFW flow	Backup	D3
	Turbine Stop Valve status	Backup	D3
	Unit 2 Feedwater Split-flow bypass valves status	Key	D2

TABLE 7.5-5
TYPE D - VARIABLES

(Sheet 3 of 6)

System/Component	Variable	Variable Function	Type/ Category
Emergency Core Cooling System (ECCS)	RWST Level	Key	D2
	Safety Injection Pump flow	Key	D2
	Safety Injection Pump Status	Key	D2
	RHR flow	Key	D2
	RHR Pump Status	Key	D2
	Centrifugal Charging Pump injection flow	Key	D2
	Centrifugal Charging Pump Status	Key	D2
	Containment Water Level	Key	D2
	ECCS valve status	Key	D2
	SI accumulator isolation valve status	Key	D2
	SI accumulator tank pressure	Key	D2
	SI accumulator tank level	Backup	D3
	Control Rod Position	Backup	D3
Auxiliary Feedwater	Flow to each S/G	Key	D2
	Pump Status	Key	D2
	Valve status	Key	D2
	CST level	Key	D2
	AFW Pump Turbine Main Steam Header Isolation Valve Status	Key	D2

TABLE 7.5-5
TYPE D - VARIABLES

(Sheet 4 of 6)

System/Component	Variable	Variable Function	Type/ Category
Containment Systems	Containment spray flow	Key	D2
	Containment Spray Pump status	Key	D2
	Containment water level	Key	D2
	Spray valve status	Key	D2
	Containment atmosphere temperature	Key	D2
	Containment Pressure (IR)	Key	D2
	Containment Spray Additive Tank Outlet Valve Status	Key	D2
	Containment Pressure (WR)	Key	D2
	Containment Spray Additive Tank Level	Key	D2
Component Cooling Water System (CCW)	Header Pressure	Key	D2
	Header Temperature	Key	D2
	Surge tank level	Key	D2
	CCW flow	Key	D2
	CCW Pump Status	Key	D2
	Valve status	Key	D2
Service Water System	Header Flow	Key	D2
	SSW Pump Status	Key	D2

IR - Intermediate Range

TABLE 7.5-5
TYPE D - VARIABLES

(Sheet 5 of 6)

System/Component	Variable	Variable Function	Type/ Category
ESF Ventilation	CR A/C Units	Key	D2
	CR Vent Damper Position	Key	D2
	CR Emergency Filtration Fans	Key	D2
	CR Emergency Pressurization Fans	Key	D2
	Primary Plant Exhaust Fan Cooler	Key	D2
	Electrical Area Fan Cooler	Key	D2
	Diesel Generator Fuel Oil Day Tank Area Vent Fan	Key	D2
	Diesel Generator Area Vent Fan	Key	D2
	SSW Intake Structure Exhaust Fan	Key	D2
	Battery Room Exhaust Fan	Key	D2
	RHR Room Fan Cooler	Key	D2
	Motor Driven AFW Pump Room Fan Cooler	Key	D2
	CCW Pump Room Fan Cooler	Key	D2
	SI Pump Room Fan Cooler	Key	D2
	Containment Spray Pump Room Fan Cooler	Key	D2
	Centrifugal Charging Pump Room Fan Cooler	Key	D2
	UPS Ventilation	Key	D2

TABLE 7.5-5
TYPE D - VARIABLES

(Sheet 6 of 6)

System/Component	Variable	Variable Function	Type/ Category
Safety Chilled Water System	Flow	Key	D2
Electric Power	Vital bus(s) voltage	Key	D2
RHR	Heat Exchanger discharge temperature	Key	D2
	Flow	Key	D2
	RHR Pump Status	Key	D2
	Valve status	Key	D2
	RCS pressure (WR)	Key	D2
	Heat Exchanger Bypass Valve Status	Backup	D3
	RHR Heat Exchanger Inlet Temperature	Backup	D3
Radioactive Waste System	High-level Radioactive Liquid Tank Level	Backup	D3
	Radioactive Gas Holdup Tank pressure	Backup	D3

TABLE 7.5-6
TYPE E - VARIABLES

Function	Variables	Variable Function	Type/ Category
Estimating Potential Release	Containment Radiation level	Key	E1
Area Radiation	Control Room Radiation	Backup	E3
	Area Radiation in locations or Areas where Access may be required[a]	Backup	E3
Assess Radioactive Releases	Plant Vent Effluent Radioactivity and flow	Key	E2
	Main Steamline Radiation	Key	E2
	Steam Generator PORV status	Key	E2
	Steam Generator Safety Valve Status	Key	E2
	Concentration of Radioactive Material discharged from liquid pathways[b]	Key	E2
	Environs Radiation	Backup	E3
	Meterological Parameters (Wind speed, Wind direction, and Atmospheric stability)	Backup	E3
	Plant Vent Effluent Particulate and Halogens	Backup	E3

a) RHR Pump Room, Sampling Room, Plant Vent Stack Sample Area, Hot Lab Area

b) Liquid Waste Effluent, Turbine Building Drains

TABLE 7.5-7
IS DELETED

PERTINENT INFORMATION IS IN TABLE 7.5-7A THRU 7.5-7C

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

(Sheet 1 of 15)

Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display: CR Displays	Location of Display: TSC/EOF Location (25)
NEUTRON FLUX	B1 (B1) NE-50A	2 PER UNIT Figure 7.1-3 NE-50B	YES %FP(WR) $0.1\text{-}10^5$ cps (SR)	$10^{-8}\text{-}2x10^2$	EQ, SQ, QA	1E	ERFCS INDICATION	YES
CONTROL ROD POSITION	B3, D3 (B3)	1 PER CONTROL ROD (53 RODS)	N/A AT VESSEL	0 to 228 steps	NONE	NON 1E	LED DISPLAY 1 PER ROD, PCS	YES
RCS SOLUABLE BORON CONCENTRATION	NONE (B3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
T(HOT) RCS (WR)	A1, B1, B2 (B1)	1 PER LOOP TE-413A TE-423A TE-433A TE-443A	YES FIGURE 7.1-3	0-700°F	EQ, SQ, QA	1E	ERFCS, RECORDER (ALL) INDICATION (LOOPS 1 & 2)	YES
T(COLD) RCS (WR)	A1, B1, B2 (B1, B3)	1 PER LOOP TE-413B TE-423B TE-433B TE-443B	YES FIGURE 7.1-3	0-700°F	EQ, SQ, QA	1E	ERFCS, RECORDER (ALL) INDICATION (LOOPS 1 & 2)	YES
RCS PRESSURE (WR)	A1, B1, B2, C1, D2, C2 (B1, C1)	3 PER UNIT PT-403 PT-3616 PT-437	YES FIGURE 7.1-3	0-3000 psig	EQ, SQ, QA	1E	ERFCS, RECORDER INDICATION	YES

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

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Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display CR Displays	Location of Display TSC/EOF Location (25)
CORE EXIT TEMPERATURE	A1, B1, C1 (C1, B3)	25 PER TRAIN TE-001 to TE-050 (27)	YES FIGURE 7.1-3	0-2300°F	EQ, SQ, QA	1E	ERFCS INDICATION (1 PER TRAIN FOR HIGHEST TEMP.)	YES
REACTOR VESSEL WATER LEVEL	B1, C2	2 PROBES (28) PER UNIT TE-3613A TE-3613B	YES IN VESSEL FIGURE 7.1-3	UPPER CORE PLATE TO TOP OF REACTOR VESSEL	EQ, SQ, QA	1E	ERFCS, LED DISPLAY	YES
RCS SUBCOOLING	A1, B1 (B2)	2 PER UNIT TY-3611 TY-3612	YES FIGURE 7.1-3	-300 to 300°F	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
CONTAINMENT WATER LEVEL (NOTE 21)	B1 B2, C2, D2 (NR-B2, C2; WR-B1, C1)	2 PER UNIT LT-4779 LT-4781	YES FIGURE 7.1-3	808'-3" to 817'-6"	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
CONTAINMENT PRESSURE (IR)	A1, B1 C2, D2 (B1, C1)	4 per unit PT-934 TO 937	YES FIGURE 7.1-3	-5 to 60 psig	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
CONTAINMENT ISOLATION VALVE STATUS	C2 (B1)	1 PER VALVE (NOTE 14)	N/A AT VALVES TABLE 6.2.4-1 AND 2	CLOSED/NOT CLOSED	EQ, SQ, QA	1E	ERFCS, INDICATION (NOTE 24)	YES

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

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Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display: CR Displays	Location of Display: TSC/EOF Location (25)
RADIATION LEVEL IN PRIMARY COOLANT	NONE (C1)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
ACCIDENT SAMPLING	NONE (C3 PRIMARY COOLANT) (E3 PRIMARY COOLANT AND SUMP) (E3 CONTAINMENT AIR)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CONTAINMENT RAD LEVEL (HR)	B2, C2, E1 (E1, C3)	2 PER UNIT RE-6290A&B	YES FIGURE 7.1-3	$1\text{-}10^{7}$R/hr.	EQ, SQ, QA	1E	ERFCS, RAD MONITOR CONSOLE	YES
CONDENSER OFF-GAS RADIATION	B2, C2 (C3)	1 PER UNIT RE-2959	N/A FIGURE 7.1-3	10^{-5} TO 10^{-1} uCi/cc	NONE (NOTE 2)	NON 1E	ERFCS, RAD MONITOR CONSOLE	YES
CONTAINMENT HYDROGEN CONCENTRATION	B3, C3 (C1)	4 PER UNIT AE-5506A THRU D	YES FIGURE 7.1-3	0-10%	EQ, SQ, QA	1E	ERFCS, INDICATION (1 PER TRAIN)	YES

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

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Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display CR Displays	Location of Display TSC/EOF Location (25)
CONTAINMENT PRESSURE (WR)	C1, D2 (C1)	2 PER UNIT PT-938 PT-939	YES FIGURE 7.1-3	0-150 psig	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
PLANT VENT EFFLUENT RADIOACTIVITY AND FLOW	C2, E2 (C1, E2)	1 PER VENT STACK X-RE-5570 A & B	N/A FIGURE 7.1-3	10^{-6} - 10^{5} uCi/cc 0-140,000 cfm	NONE (NOTE 3)	NON 1E	ERFCS, RAD MONITOR CONSOLE	YES
AREA RAD. LEVELS ADJACENT CONTAINMENT	C3 (C2)	11 PER UNIT RE-6259 A&B RE-6291 A&B RE-6292 THRU RE-6297	N/A FIGURE 7.1-3	10^{-1} - 10^{4} R/hr	NONE	NON 1E	ERFCS, RAD. MONITOR CONSOLE	YES
		RE-5637 3 (SHARED)		10^{-4}-10^{o} uCi/cc				
		XRE-6273 XRE-6275		10^{-1}-10^{4} mR/hr				
		XRE-5702		10^{-4}-10^{o} uCi/cc				
EFFLUENT RADIOACTIVITY AND FLOW NOBLE GASES-AREAS ADJACENT CONTAINMENT	C2, E2 (C2, E2)	1 PER VENT STACK X-RE-5570 A & B	N/A FIGURE 7.1-3	10^{-6} - 10^{5} uCi/cc 0-140,000 cfm	NONE (NOTE 3)	NON 1E	ERFCS, RAD MONITOR CONSOLE	YES

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

(Sheet 5 of 15)

Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display CR Displays	Location of Display TSC/EOF Location (25)
RHR HEAT EXCHANGER DISCHARGE TEMPERATURE	D2 (D2)	1 PER TRAIN TE-604 TE-605	N/A FIGURE 7.1-3	50-400°F	EQ, QA (NOTE 20)	NON 1E	ERFCS, RECORDER	YES
SI ACCUMULATOR TANK LEVEL	D3 (D2)	2 PER TANK LT-950 TO 957	N/A FIGURE 7.1-3	0-100%	NONE (NOTES 5 AND 6)	NON 1E	ERFCS, INDICATION	YES
SI ACCUMULATOR TANK PRESSURE	D2 (D2)	2 PER TANK PT-960 TO 967	N/A FIGURE 7.1-3	0-700 psig	EQ, QA (NOTE 5 AND 20)	NON 1E	ERFCS, INDICATION	YES
SI ACCUMULATOR ISOLATION VALVE STATUS	D2 (D2)	1 PER VALVE 8808A, B, C, AND D	N/A AT VALVE	OPEN/NOT OPEN	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
BORIC ACID CHARGING FLOW (NOTE 10)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CENTRIFUGAL CHARGING PUMP INJECTION FLOW (NOTE 10)	D2 (D2)	1 PER UNIT FT-917	N/A FIGURE 7.1-3	0-1000 gpm	EQ, QA (NOTES 5 AND 20)	NON 1E	ERFCS, INDICATION	YES
SAFETY INJECTION PUMP FLOW (HPI SYSTEM) (NOTE 10)	D2 (D2)	1 PER PUMP FT-918 FT-922	N/A FIGURE 7.1-3	0-800 gpm	EQ, QA (NOTES 5 AND 20)	NON 1E	ERFCS, INDICATION	YES

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

(Sheet 6 of 15)

Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display CR Displays	Location of Display TSC/EOF Location (25)
RHR FLOW (LPI SYSTEM) (NOTE 10)	D2 (D2)	1 PER TRAIN FT-618 FT-619	N/A FIGURE 7.1-3	0-5500 gpm	EQ, QA (NOTE 5 AND 20)	NON 1E	ERFCS, INDICATION	YES
RWST LEVEL	A1, D2 (D2)	4 PER UNIT LT-930 TO 933	YES FIGURE 7.1-3	0-100%	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
REACTOR COOLANT PUMP STATUS (MOTOR CURRENT)	D3 (D3)	1 PER MOTOR 1PCPX1,2PCPX1 1PCPX2,2PCPX2 1PCPX3,2PCPX3 1PCPX4,2PCPX4	N/A AT SWITCHGEAR	0-800 amp	NONE	NON 1E	ERFCS, INDICATION	YES
PRESSURIZER PORV STATUS	D2 (D2)	1 PER VALVE PCV-455A PCV-456	N/A AT VALVE	CLOSED/NOT CLOSED OPEN/NOT OPEN	EQ, SQ, QA	1E	ERFCS, INDICATION (NOTE 15)	YES
PRESSURIZER SAFETY VALVE STATUS	D2 (D2)	1 PER VALVE 8010A 8010B 8010C	N/A AT VALVE	CLOSED/NOT CLOSED	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
PRESSURIZER LEVEL	A1, B1, D2 (D1)	3 PER UNIT LT-459 LT-460 LT-461	YES FIGURE 7.1-3	0-100%	EQ, SQ, QA	1E	ERFCS, RECORDER, INDICATION	YES

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

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Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display CR Displays	Location of Display TSC/EOF Location (25)
PRESSURIZER HEATER CURRENT	D2 (D2)	1 PER HEATER BANK PCPR PCPR1 PCPR2 PCPR3	N/A AT SWITCHGEAR	0-1000A	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
PRESSURIZER RELIEF TANK LEVEL (QUENCH TANK)	D3 (D3)	1 PER UNIT LT-470	N/A FIGURE 7.1-3	0-100%	NONE	NON 1E	ERFCS, INDICATION	YES
PRESSURIZER RELIEF TANK TEMPERATURE (QUENCH TANK)	D3 (D3)	1 PER UNIT TE-468	N/A FIGURE 7.1-3	50-350°F	NONE	NON 1E	ERFCS, INDICATION	YES
PRESSURIZER RELIEF TANK PRESSURE (QUENCH TANK)	D3 (D3)	1 PER UNIT PT-469	N/A FIGURE 7.1-3	0-100 psig	NONE	NON 1E	ERFCS, INDICATION	YES
STEAM GENERATOR WATER LEVEL (WR)	B1, D2 (D1)	1 PER STEAM GENERATOR LT-501 LT-502 LT-503 LT-504	N/A FIGURE 7.1-3	0-100%	EQ, SQ, QA	1E	ERFCS, RECORDER, INDICATION	YES

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

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Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display CR Displays	Location of Display TSC/EOF Location (25)
STEAM GENERATOR WATER LEVEL (NR)	A1, B1, D2 (NONE-PLANT SPECIFIC)	4 PER STEAM GENERATOR LT-517 TO 519 LT-527 TO 529 LT-537 TO 539 LT-547 TO 549 LT-551 TO 554	YES FIGURE 7.1-3	0-100%	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
MAIN STEAMLINE PRESSURE (S/G PRESSURE)	A1, B1, D2 (D2)	3 PER LOOP PT-514 TO 516 PT-524 TO 526 PT-534 TO 536 PT-544 TO 546	YES FIGURE 7.1-3	0-1300 psig	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
STEAM GENERATOR SAFETY VALVE STATUS	D2, E2 (D2, E2)	1 PER VALVE PV-2444A TO E PV-2445A TO E PV-2446A TO E PV-2447A TO E	N/A AT VALVE	CLOSED/NOT CLOSED	EQ, QA (NOTES 6 and 20)	NON 1E	ERFCS	YES
STEAM GENERATOR PORV STATUS	D2, E2 (D2, E2)	1 PER VALVE PV-2325 THRU PV-2328	N/A AT VALVE	CLOSED/NOT CLOSED OPEN/NOT OPEN	EQ, SQ, QA	1E	ERFCS, INDICATION (NOTE 15)	YES
MAIN FEEDWATER FLOW	D3 (D3)	1 PER STEAM GENERATOR FT-511 FT-521 FT-531 FT-541	N/A FIGURE 7.1-3	0 TO $5X10^6$ lb/hr	NONE	NON 1E	ERFCS, INDICATION, RECORDER	YES

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

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Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display: CR Displays	Location of Display: TSC/EOF Location (25)
AUXILIARY FEEDWATER FLOW	A1, B1, D2 (D2)	2 PER STEAM GENERATOR FT-2463 A&B FT-2464 A&B FT-2465 A&B FT-2466 A&B	YES FIGURE 7.1-3	0-550 gpm	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
CST WATER LEVEL	A1, D2 (D1)	2 PER UNIT LT-2478 LT-2479	YES FIGURE 7.1-3	0-100%	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
CONTAINMENT SPRAY FLOW	D2 (D2)	1 PER PUMP FT-4772-1&2 FT-4773-1&2	N/A FIGURE 7.1-3	0-4000 gpm	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
HEAT REMOVAL BY CONTAINMENT FAN HEAT REMOVAL SYSTEM (NOTE 7)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CONTAINMENT ATMOSPHERE TEMPERATURE	D2 (D2)	4 PER UNIT TE-5400 TO TE-5403	N/A FIGURE 7.1-3	0 TO 360°F	EQ, SQ, QA	1E	ERFCS, INDICATION FOR AVERAGE TEMPERATURE	YES
CONTAINMENT SUMP WATER TEMPERATURE (NOTE 8)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

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Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display CR Displays	Location of Display TSC/EOF Location (25)
CVCS CHARGING SYSTEM MAKEUP FLOW	D2 (D2)	1 PER UNIT FT-121	N/A FIGURE 7.1-3	0-200 gpm	NONE (NOTE 5 AND 16)	NON 1E	ERFCS, INDICATION	YES
CVCS LETDOWN FLOW	D2 (D2)	1 PER UNIT FT-132	N/A FIGURE 7.1-3	0-200 gpm	NONE (NOTE 5 AND 16)	NON 1E	ERFCS, INDICATION	YES
VOLUME CONTROL TANK LEVEL	D2 (D2)	1 PER UNIT LT-112	N/A FIGURE 7.1-3	0-100%	NONE (NOTE 5 AND 16)	NON 1E	ERFCS, INDICATION	YES
CCW HEADER TEMPERATURE	D2 (D2)	1 PER HEADER TE-4530 TE-4534	N/A FIGURE 7.1-3	30-150°F	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
CCW FLOW	D2 (D2)	1 PER TRAIN FT-4536A FT-4537A	N/A FIGURE 7.1-3	0-20,000 gpm	EQ, SQ, QA	1E	ERFCS, INDICATION RECORDER	YES
SERVICE WATER HEADER FLOW	D2 (D2)	1 PER TRAIN FT-4258 FT-4259	N/A FIGURE 7.1-3	0-20,000 gpm	EQ, SQ, QA	1E	ERFCS, INDICATION, RECORDER	YES
HIGH LEVEL RADIOACTIVE LIQUID TANK LEVEL (NOTE 9)	D3 (D3)	1 PER TANK LT-1003 X-LT-1001	N/A FIGURE 7.1-3	0-100%	NONE	NON 1E	NO	NO

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

(Sheet 11 of 15)

Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display: CR Displays	Location of Display: TSC/EOF Location (25)
RADIOACTIVE GAS HOLDUP TANK PRESSURE (NOTE 9)	D3 (D3)	1 PER TANK X-PT-1036 TO 1039 X-PT-1052 TO 1057	N/A FIGURE 7.1-3	0-150 psig	NONE	NON 1E	NO	N0
CR VENT DAMPER POSITION (EMERGENCY VENTILATION DAMPER POSITION) (NOTE 17)	D2 (D2)	1 PER DAMPER X-HV-5826, 5829, 5825 A&B 5828 A&B 5857, 5858, 5883, X-PV-5855, X-PV-5856	N/A AT DAMPER	CLOSED/NOT CLOSED	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
		X-HV-5831 5834, 5837 5838, 5839 5840, 5847 5848, 5851 5853		OPEN/NOT OPEN				
VITAL BUS VOLTAGE AVAILABILITY	D2 (D2)	1 PER BUS 1EA1, 1EA2 1ED1, 1ED2 1ED3, 1ED4	N/A AT SWITCHGEAR	0-9000 VAC 100-150 VDC	EQ, SQ, QA	1E	ERFCS, INDICATION	YES
		1EB1, 1EB2 1EB3, 1EB4 2EA1, 2EA2		0-600 VAC			ERFCS	

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

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Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display: CR Displays	Location of Display: TSC/EOF Location (25)
		2ED1, 2ED2 2ED3, 2ED4 2EB1, 2EB2 2EB3, 2EB4 1 PER PANEL 1PC1, 1PC2 1PC3, 1PC4 1EC1, 1EC3 1EC2, 1EC4 1EC5, 1EC6 2PC1, 2PC2 2PC3, 2PC4 2EC1, 2EC3 2EC2, 2EC4 2EC5, 2EC6		0-150 VAC				
CR AREA RADIATION	E3 (E2)	2 PER PLANT XRE-6281 XRE-6282	N/A FIGURE 7.1-3	10^{-1} - 10^{4} mR/hr	NONE	NON 1E	ERFCS, RAD MONITOR CONSOLE	YES
RHR PUMP ROOM AREA RADIATION	E3 (E2)	1 PER ROOM RE-6260A RE-6260B	N/A FIGURE 7.1-3	10^{-1} - 10^{4} R/hr (NOTE 22)	NONE	NON 1E	ERFCS, RAD MONITOR CONSOLE	YES
PASS ROOM AREA RADIATION	E3 (E2)	1 PER ROOM RE-6261	N/A FIGURE 7.1-3	10^{-1} - 10^{4} mR/hr (NOTE 22)	NONE	NON 1E	ERFCS, RAD MONITOR CONSOLE	YES
PLANT VENT	E3	2 PER SITE	N/A	10^{-1} - 10^{4}	NONE	NON 1E	ERFCS,	YES

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

(Sheet 13 of 15)

Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display: CR Displays	Location of Display: TSC/EOF Location (25)
STACK SAMPLE AREA RADIATION	(E2)	1-RE-6259 2-RE-6259	FIGURE 7.1-3	mR/hr (NOTE 22)			RAD MONITOR CONSOLE	
HOT LAB AREA RADIATION	E3 (E2)	1 PER SITE X-RE-6283	N/A FIGURE 7.1-3	10^{-1} - 10^{4} mR/hr (NOTE 22)	NONE	NON 1E	ERFCS, RAD MONITOR CONSOLE	YES
COMMON PLANT VENT INCLUDING CONTAINMENT PURGE, AUXILIARY BUILDING AND OTHER AREAS NOBLE GASES, VENT FLOW, PARTICULATES, AND HALOGENS	C2, E2 (C2, E2)	1 PER VENT STACK X-RE-5570 A&B	N/A FIGURE 7.1-3	10^{-6} - 10^{5} uCi/cc 0-140,000 cfm	NONE (NOTE 3)	NON 1E	ERFCS, RAD MONITOR CONSOLE	YES
AIRBORNE RADIO HALOGENS AND PARTICULATES	E3 (E3)	GRAB SAMPLE	N/A	10^{-9} - 10^{-3} uCi/cc	NONE	NON 1E	N/A	N/A
REACTOR SHIELD BUILDING ANNULUS	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PLANT VENT EFFLUENT PARTICULATE AND HALOGEN	E3 (E3)	GRAB SAMPLE	10^{-3} - 10^{-2} uCi/cc	NONE	NON 1E	N/A	N/A	

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

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Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display: CR Displays	Location of Display: TSC/EOF Location (25)
MAIN STEAMLINE RADIATION	E2 (E2)	1 PER STEAMLINE RE-2325 RE-2326 RE-2327 RE-2328	N/A FIGURE 7.1-3	10^{-1} - 10^{3} uCi/cc	NONE (NOTE 2)	NON 1E	ERFCS, RAD MONITOR CONSOLE	YES
RADIATION EXPOSURE METERS	N/A (NOTE 23)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
ENVIRONS RADIATION	E3 (E3)	AS REQUIRED (PORTABLE)	N/A	10^{-3} - 10^{4} R/HR FOR PHOTONS 10^{-3} - 10^{4} RADS/HR FOR BETA AND LOWER ENERGY PHOTONS	NONE	SELF CONTAINED BATTERY	NO	NO
WIND DIRECTION	E3 (E3)	3 PER SITE X-ZE-4115 X-ZE-4116 X-ZE-4126	N/A METEOROLOGICAL TOWERS	0-540 DEGREES	NONE	NON 1E	ERFCS, RAD MONITOR CONSOLE RECORDER	YES
WIND SPEED	E3 (E3)	3 PER SITE X-SE-4117 X-SE-4118 X-SE-4128	N/A METEOROLOGICAL TOWERS	0-100 mph	NONE	NON 1E	ERFCS, RAD MONITOR CONSOLE, RECORDER	YES

TABLE 7.5-7A
INSTRUMENT SUMMARY DATA FOR VARIABLES IN TABLE 2 OF REG. GUIDE 1.97, REV 2

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Variable	Type/ Category CPNPP (RG 1.97)	Quantity Tag Numbers	Redundance and Sensor Location (11)	Instrument Range (1)	QA and Qualification (19)	Power Supply	Location of Display: CR Displays	Location of Display: TSC/EOF Location (25)
ATMOSPHERIC STABILITY	E3 (E3)	2 PER SITE X-TY-4119 X-TY-4120	N/A METEOROLOGICAL PRIMARY TOWER	-5 TO +15°F	NONE	NON 1E	ERFCS, RAD MONITOR CONSOLE, RECORDER	YES
POST ACCIDENT SAMPLING SYSTEM	NONE (C3 PRIMARY COOLANT) (E3 PRIMARY COOLANT AND SUMP) (E3 CONTAINMENT AIR)	N/A	N/A	N/A	N/A	N/A	N/A	N/A

TABLE 7.5-7B
INSTRUMENT SUMMARY DATA FOR ACCIDENT MONITORING VARIABLES FOR CPNPP NOT IN TABLE 2 OF REG. GUIDE 1.97, REV.2

(Sheet 1 of 11)

VARIABLE	CPNPP TYPE/ CATEGORY	QUANTITY TAG NUMBERS	TAG NUMBERS	REDUNDANCE AND SENSOR LOCATION (11)	INSTRUMENT RANGE (1)	QA AND QUALIFICATION(19)	POWER SUPPLY	LOCATION OF DISPLAY (18) CR DISPLAY
STEAM GENERATOR BLOWDOWN RAD.	B2, C2	1 per unit RE-4200		N/A FIGURE 7.1-3	10^{-5}-5x10^{-2} uCi/cc	NONE (NOTE 2)	NON 1E	RAD MONITOR CONSOLE
RHR HEAT EXCHANGER BYPASS VALVE	D3	1 PER VALVE FCV-618 FCV-619		N/A AT VALVE	CLOSED/ NOT CLOSED	NONE	NON 1E	INDICATION
RHR HEAT EXCHANGER INLET TEMPERATURE	D3	1 PER TRAIN TE-612 TE-613		N/A FIGURE 7.1-3	50-400°F	NONE	NON 1E	ERFCS RECORDER
RHR VALVE	D2	1 PER VALVE		N/A	OPEN/NOT OPEN	EQ, SQ, QA	1E	INDICATION
STATUS		8701-A&B 8702-A&B FCV-610 FCV-611		AT VALVE	CLOSED/ NOT CLOSED			
BORIC ACID TANK LEVEL	D2	2 PER TANK (4 SHARED) X-LT-102 X-LT-104 X-LT-105 X-LT-106		N/A FIGURE 7.1-3	0-100%	EQ, SQ, QA	1E	INDICATION
ECCS VALVE STATUS	D2	1 PER VALVE LCV-112B&C 8105 8801A&B 8812A&B 8811A&B		N/A AT VALVE	*VARIOUS (NOTE 13)	EQ, SQ, QA	1E	INDICATION

TABLE 7.5-7B
INSTRUMENT SUMMARY DATA FOR ACCIDENT MONITORING VARIABLES FOR CPNPP NOT IN TABLE 2 OF REG. GUIDE 1.97, REV.2

(Sheet 2 of 11)

VARIABLE	CPNPP TYPE/ CATEGORY	QUANTITY TAG NUMBERS	TAG NUMBERS	REDUNDANCE AND SENSOR LOCATION (11)	INSTRUMENT RANGE (1)	QA AND QUALIFICATION(19)	POWER SUPPLY	LOCATION OF DISPLAY (18) CR DISPLAY
		8809A&B 8808 A,B,C,D 8804A&B 8106 8716A&B 8807A&B 8924 8840 8802A&B 8821A&B 8835 8814A&B 8813						
	D2	8923A&B 8806 8220 8221 8110 8111 8511A&B 8512A&B 8202A&B 8210 A&B LCV-112D LCV-112E 8701A&B 8702A&B						
CCW TO RCP VALVE STATUS	D2	1 PER VALVE HV-4699, 4512 HV-4700, 4513 HV-4709,4515 HV-4708, 4524		N/A	OPEN/NOT OPEN	EQ, SQ, QA	1E	INDICATION

TABLE 7.5-7B
INSTRUMENT SUMMARY DATA FOR ACCIDENT MONITORING VARIABLES FOR CPNPP NOT IN TABLE 2 OF REG. GUIDE 1.97, REV.2

(Sheet 3 of 11)

VARIABLE	CPNPP TYPE/ CATEGORY	QUANTITY TAG NUMBERS	TAG NUMBERS	REDUNDANCE AND SENSOR LOCATION (11)	INSTRUMENT RANGE (1)	QA AND QUALIFICATION(19)	POWER SUPPLY	LOCATION OF DISPLAY (18) CR DISPLAY
		HV-4701, 4525 HV-4696, 4526 HV-4514, 4527						
RCP SEAL WATER INJECTION FLOW	D3	1 PER RCP FT-142 FT-143 FT-144 FT-145		N/A FIGURE 7.1-3	0-20 gpm	NONE (NOTE 6)	NON 1E	INDICATION
S/G BLOWDOWN ISOLATION VALVE STATUS	D2	1 PER VALVE HV-2397 -2397A HV-2398 -2398A HV-2399 -2399A HV-2400 -2400A		N/A AT VALVE	CLOSED/ NOT CLOSED	EQ, SQ, QA	1E	INDICATION
MSIV & BYPASS VALVE STATUS	D2	1 PER VALVE HV-2333 A&B HV-2334 A&B HV-2335 A&B HV-2336 A&B		N/A AT VALVE	CLOSED/ NOT CLOSED	EQ, SQ, QA	1E	INDICATION

TABLE 7.5-7B
INSTRUMENT SUMMARY DATA FOR ACCIDENT MONITORING VARIABLES FOR CPNPP NOT IN TABLE 2 OF REG. GUIDE 1.97, REV.2

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VARIABLE	CPNPP TYPE/ CATEGORY	QUANTITY TAG NUMBERS	TAG NUMBERS	REDUNDANCE AND SENSOR LOCATION (11)	INSTRUMENT RANGE (1)	QA AND QUALIFICATION(19)	POWER SUPPLY	LOCATION OF DISPLAY (18) CR DISPLAY
AFW PUMP TURBINE MAIN STEAM HEADER ISOLATION VALVE STATUS	D2	1 PER VALVE HV-2452-1 HV-2452-2		N/A AT VALVE	CLOSED/ NOT CLOSED OPEN/NOT OPEN	EQ, SQ, QA	1E	INDICATION
MAIN FEEDWATER CONTROL AND BYPASS VALVE STATUS	D2	1 PER VALVE FCV-510 520, 530 540, LCV-2162 LCV-2163 LCV-2164 LCV-2165		N/A AT VALVE	CLOSED/ NOT CLOSED	EQ, QA	1E	INDICATION
MAIN FEEDWATER ISOLATION AND BYPASS VALVE STATUS	D2	1 PER VALVE HV-2134 to 2137 2-FV-2193 to 2196 HV-2185 to 2188		N/A AT VALVE	CLOSED/ NOT CLOSED	EQ, SQ, QA	1E	INDICATION
FEEDWATER SPLIT-FLOW BYPASS VALVES STATUS	D2	1 per valve 2-FV-2181 TO 2184		N/A AT VALVE	CLOSED/ NOT CLOSED	EQ, SQ, QA	1E	INDICATION
TURBINE STOP VALVE STATUS	D3	1 PER VALVE UV-2413 TO 2416 UV-2428 TO 2431		N/A AT VALVE	CLOSED/ NOT CLOSED	NONE	NON 1E	INDICATION

TABLE 7.5-7B
INSTRUMENT SUMMARY DATA FOR ACCIDENT MONITORING VARIABLES FOR CPNPP NOT IN TABLE 2 OF REG. GUIDE 1.97, REV.2

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VARIABLE	CPNPP TYPE/ CATEGORY	QUANTITY TAG NUMBERS	TAG NUMBERS	REDUNDANCE AND SENSOR LOCATION (11)	INSTRUMENT RANGE (1)	QA AND QUALIFICATION(19)	POWER SUPPLY	LOCATION OF DISPLAY (18) CR DISPLAY
AUXILIARY FEEDWATER VALVE STATUS	D2	1 PER VALVE PV-2453A,B PV-2454A,B HV-2459 to HV-2462 HV-2491A,B HV-2492A,B HV-2493A,B HV-2494A,B FV-2456 FV-2457		N/A AT VALVE	CLOSED/ NOT CLOSED OPEN/NOT OPEN	EQ, SQ, QA	1E	INDICATION
CONTAINMENT SPRAY VALVE STATUS	D2	1 PER VALVE HV-4777, HV-4773-1&2 HV-4759 HV-4776 FV-4772-1&2 HV-4758 HV-4782 HV-4783		N/A AT VALVE	*VARIOUS (NOTE 13)	EQ, SQ, QA	1E	INDICATION
CCW HEADER PRESSURE	D2	1 PER HEADER PT-4520 PT-4521		N/A FIGURE 7.1-3	0-200 psig	EQ, SQ, QA	1E	INDICATION
CCW SURGE TANK LEVEL	D2	1 PER TRAIN LT-4500 LT-4501		N/A FIGURE 7.1-3	0-100%	EQ, SQ, QA	1E	INDICATION RECORDER
CVCS VALVE STATUS	D2	1 PER VALVE 8100, 8112 8160, 8152 8146, 8147		N/A AT VALVE	*VARIOUS (NOTE 13)	EQ, SQ, QA NOTE 26	1E	INDICATION

TABLE 7.5-7B
INSTRUMENT SUMMARY DATA FOR ACCIDENT MONITORING VARIABLES FOR CPNPP NOT IN TABLE 2 OF REG. GUIDE 1.97, REV.2

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VARIABLE	CPNPP TYPE/ CATEGORY	QUANTITY TAG NUMBERS	TAG NUMBERS	REDUNDANCE AND SENSOR LOCATION (11)	INSTRUMENT RANGE (1)	QA AND QUALIFICATION(19)	POWER SUPPLY	LOCATION OF DISPLAY (18) CR DISPLAY
		LCV-459, LCV-460, 8145, 8149A,B,C 8153, 8154 LCV-112B&C 8104, 8105 8106						
CCW VALVE STATUS	D2	1 PER VALVE HV-4513 HV-4512 HV-4572 HV-4573 HV-4574 HV-4575 FV-4537 FV-4536 HV-4514 HV-4515 HV-4524 THRU 4527		N/A AT VALVE	*VARIOUS (NOTE 13)	EQ, SQ, QA	1E	INDICATION
CR A/C UNITS	D2	4 (SHARED) CPX-VAACCR 01 THRU 04		N/A FIGURE 9.4-1	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
CR EMERGENCY FILTRATION FANS	D2	2 (SHARED) CPX-VAFNCB-23 CPX-VAFNCB-24		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
CR EMERGENCY PRESSURIZATION FAN	D2	2 (SHARED) CPX-VAFNCB-05 CPX-VAFNCB-06		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION

TABLE 7.5-7B
INSTRUMENT SUMMARY DATA FOR ACCIDENT MONITORING VARIABLES FOR CPNPP NOT IN TABLE 2 OF REG. GUIDE 1.97, REV.2

(Sheet 7 of 11)

VARIABLE	CPNPP TYPE/ CATEGORY	QUANTITY TAG NUMBERS	TAG NUMBERS	REDUNDANCE AND SENSOR LOCATION (11)	INSTRUMENT RANGE (1)	QA AND QUALIFICATION(19)	POWER SUPPLY	LOCATION OF DISPLAY (18) CR DISPLAY
PRIMARY PLANT	D2	4 (SHARED) CPX-VAFNCB -07, 08, 21, 22		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	EXHAUST FAN
ELECTRICAL AREA FAN COOLER	D2	4 PER UNIT CP1/2-VAAUSE- -15,16,17,18		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
DIESEL GENERATOR FUEL OIL DAY TANK AREA VENT FAN	D2	2 PER UNIT CP1/2-VAFNCB -04, 05		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
DIESEL GENERATOR AREA VENT FAN	D2	8 PER UNIT CP1/2-VAFNAV-25 26, 27, 28 29, 30, 31 32		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
SSW INTAKE STRUCTURE EXHAUST FAN	D2	8 (SHARED) CPX-VAFNWV -02, 03, 04, 05, 06, 07, 08, 09		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
BATTERY ROOM EXHAUST FAN	D2	4 PER UNIT CP1/2-VAFNID -07, 08 09, 10		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
RHR ROOM FAN COOLER	D2	2 PER UNIT CP1/2-VAAUSE -01, 02		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION

TABLE 7.5-7B
INSTRUMENT SUMMARY DATA FOR ACCIDENT MONITORING VARIABLES FOR CPNPP NOT IN TABLE 2 OF REG. GUIDE 1.97, REV.2

(Sheet 8 of 11)

VARIABLE	CPNPP TYPE/ CATEGORY	QUANTITY TAG NUMBERS	TAG NUMBERS	REDUNDANCE AND SENSOR LOCATION (11)	INSTRUMENT RANGE (1)	QA AND QUALIFICATION(19)	POWER SUPPLY	LOCATION OF DISPLAY (18) CR DISPLAY
MOTOR DRIVEN AFW PUMP ROOM FAN	D2	2 PER UNIT CP1/2-VAAUSE -07, 08		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
CCW PUMP ROOM FAN COOLER	D2	2 PER UNIT CP1/2-VAAUSE -09, 10		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
SI PUMP ROOM FAN COOLER	D2	2 PER UNIT CP1/2-VAAUSE -05, 06		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
CONTAINMENT SPRAY PUMP ROOM FAN COOLER	D2	4 PER UNIT CP1/2-VAAUSE -11, 12, 13, 14		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
CENTRIFUGAL CHARGING PUMP ROOM FAN COOLER	D2	2 PER UNIT CP1/2-VAAUSE -03, 04		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
UPS VENTILATION	D2	4 (SHARED) CPX-VAACUP -01, 02, and CPX-VAFNAV 42, 43		N/A AT MCC	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
SAFETY CHILLED WATER FLOW	D2	1 PER TRAIN FT-6708 FT-6709		N/A FIGURE 7.1-3	0-400 gpm	None (NOTE 6)	NON 1E	INDICATION
LIQUID WASTE EFFLUENT RAD.	E2	1 (SHARED) X-RE-5253		N/A FIGURE 7.1-3	10^{-5} - $5x10^{-2}$ uCi/cc	NONE (NOTE 3)	NON 1E	RAD MONITOR CONSOLE

TABLE 7.5-7B
INSTRUMENT SUMMARY DATA FOR ACCIDENT MONITORING VARIABLES FOR CPNPP NOT IN TABLE 2 OF REG. GUIDE 1.97, REV.2

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VARIABLE	CPNPP TYPE/ CATEGORY	QUANTITY TAG NUMBERS	TAG NUMBERS	REDUNDANCE AND SENSOR LOCATION (11)	INSTRUMENT RANGE (1)	QA AND QUALIFICATION(19)	POWER SUPPLY	LOCATION OF DISPLAY (18) CR DISPLAY
TURBINE BUILDING DRAINS RADIATION	E2	1 PER UNIT RE-5100		N/A FIGURE 7.1-3	10^{-5} - $5x10^{-2}$ uCi/cc	NONE (NOTE 3)	NON 1E	RAD MONITOR CONSOLE
RCP SEAL INJECTION ISOLATION VALVE STATUS	D2	1 PER VALVE 8351A-D		N/A AT VALVE	OPEN/NOT OPEN	EQ, SQ, QA	1E	INDICATION
PRESSURIZER PORV BLOCK VALVE STATUS	D2	1 PER VALVE 8000 A&B		N/A AT VALVE	CLOSED/ NOT CLOSED OPEN/NOT OPEN	EQ, SQ, QA	1E	INDICATION
STEAM GENERATOR SAMPLING ISOLATION VALVE STATUS	D2	1 PER VALVE HV-2405, 2406, 2407 2408, 2401 A&B 2402 A&B 2403 A&B 2404 A&B		N/A AT VALVE	CLOSED/ NOT CLOSED	EQ, SQ, QA	1E	INDICATION
LIQUID WASTE EFFLUENT RAD	E2	1(SHARED) X-RE-5251A		N/A FIGURE 7.1-3	10^{-5}-5X10^{-2} uCi/cc	NONE (NOTE 3)	NON IE	RAD MONITOR CONSOLE
CENTRIFUGAL CHARGING PUMPS (CCP) STATUS	D2	1 PER PUMP TBX/TCX-CSAPCH -01, 02		N/A AT SWITCHGEAR	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
SAFETY INJECTION PUMP (SIP) STATUS	D2	1 PER PUMP TBX/TCX-SIAPSI -01, 02		N/A AT SWITCHGEAR	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION

TABLE 7.5-7B
INSTRUMENT SUMMARY DATA FOR ACCIDENT MONITORING VARIABLES FOR CPNPP NOT IN TABLE 2 OF REG. GUIDE 1.97, REV.2

(Sheet 10 of 11)

VARIABLE	CPNPP TYPE/ CATEGORY	QUANTITY TAG NUMBERS	TAG NUMBERS	REDUNDANCE AND SENSOR LOCATION (11)	INSTRUMENT RANGE (1)	QA AND QUALIFICATION(19)	POWER SUPPLY	LOCATION OF DISPLAY (18) CR DISPLAY
RESIDUAL HEAT REMOVAL PUMP (RHR) STATUS	D2	1 PER PUMP TBX/TCX-RHAPRH -01, 02		N/A AT SWICHGEAR	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
RHR PUMP SUCTION PRESSURE	02	1 PER PUMP	PT-601A PT-602A	N/A AT PUMP SUCTION	0-60 PSIG	EQ, QA NOTES 6 AND 20	N1E	ERFCS
CONTAINMENT SPRAY PUMP (CSP) STATUS	D2	1 PER PUMP CP1/2-CTAPCS -01, 02, 03, 04		N/A AT SWITCHGEAR	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
CONTAINMENT SPRAY PUMP SUCTION PRESSURE	D2	1 PER TRAIN	PT-4806A PT-4807A	N/A AT PUMP SUCTION	0-60 PSIG	EQ, QA NOTES 6 AND 20	N1E	ERFCS
CONTAINMENT SPRAY ADDITIVE TANK LEVEL	D2	2 PER TANK LT-4752 LT-4753		N/A AT TANK	0-100%	EQ, SQ, QA	1E	INDICATION
CONTAINMENT SPRAY ADDITIVE TANK OUTLET VALVE	D2	1 PER VALVE LV-4752 THRU LV-4755		N/A AT VALVE OPEN/NOT OPEN	CLOSED/ NOT CLOSED	EQ, SQ, QA	1E	INDICATION
COMPONENT COOLING WATER PUMP STATUS	D2	1 PER PUMP CP1/2-CCAPCC -01, 02		N/A AT SWITCHGEAR	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION
AUXILIARY FEEDWATER PUMP STATUS	D2	1 PER PUMP CP1/2-AFAPMD 01 & 02		N/A AT SWITCHGEAR	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION

TABLE 7.5-7B
INSTRUMENT SUMMARY DATA FOR ACCIDENT MONITORING VARIABLES FOR CPNPP NOT IN TABLE 2 OF REG. GUIDE 1.97, REV.2

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VARIABLE	CPNPP TYPE/ CATEGORY	QUANTITY TAG NUMBERS	TAG NUMBERS	REDUNDANCE AND SENSOR LOCATION (11)	INSTRUMENT RANGE (1)	QA AND QUALIFICATION(19)	POWER SUPPLY	LOCATION OF DISPLAY (18) CR DISPLAY
STATION SERVICE WATER PUMP STATUS	D2	1 PER PUMP CP1/2-SWAPSW -01, 02		N/A AT SWITCHGEAR	RUNNING/ NOT RUNNING	EQ, SQ, QA	1E	INDICATION

TABLE 7.5-7C
NOTES AND ABBREVIATIONS FOR TABLES 7.5-7A AND 7.5-7B

(Sheet 1 of 4)

1. Instrumentation ranges may vary from Regulatory Guide 1.97 Revision 2. However, CPNPP instrument ranges envelope the requirements of Reg. Guide 1.97 Rev. 2 unless otherwise specified in Table 7.5-7D.

2. Main Steamline Radiation, Condenser Off-Gas Radiation, and Steam Generator Blowdown Radiation are only required for steam generator tube rupture detection. These Non-Class 1E Monitors are in mild environments for the duration of this event and therefore do not require environmental qualification.

3. These radiation monitors are located in a mild environment for the duration of the events for which they are required.

4. Not used.

5. Instruments are seismically qualified for pressure boundary integrity.

6. Instruments are seismically mounted.

7. CPNPP does not take credit for this system during an accident.

8. Containment air temperature and RHR heat exchanger temperature provide equivalent information for Containment Sump Water Temperature.

9. These instruments provide indication at the local waste processing panels and annunciation from the panels is provided in the control room to alarm when there is a potential for over filling the tanks.

10. Boric acid charging flow at CPNPP is not an accident monitoring variable because it is not used for Safety Injection. Safety Injection Flow is provided by Centrifugal Charging Pump Flow, Safety Injection Flow, and RHR Flow.

11. Redundancy is listed as N/A for all Category 2 and 3 instrument channels since it is not required (although redundancy may, in fact, exist). A response of “Yes” means that separate safety- related trains are used and the redundant channels, including sensors, have the required separation and independence.

12. The QA and Qualification information applies to the Class 1E isolation valves only.

13. “*Various” for Range means that different positions are monitored for different valves including open/not open and/or closed/not closed and/or intermediate positions.

14. All valves listed in FSAR Table 6.2.4-2 except local manual, check, relief and safety valves.

15. ERFCS displays the valve position requirements (e.g. Closed/Not Closed) of Reg. 1.97, Rev. 2 Table 2.

TABLE 7.5-7C
NOTES AND ABBREVIATIONS FOR TABLES 7.5-7A AND 7.5-7B

(Sheet 2 of 4)

16. These parameters are D2 variables (Non 1E Devices) as they monitor other systems normally employed for safe shutdown but are not required during or following an accident (per section 7.5.1.1.1). When required to function, these instruments are in a mild environment and therefore do not require environmental qualification.

17. Only CR Ventilation dampers are listed on Table 7.5-7A because we understand that the intent of the variable “Emergency Ventilation Dampers” in Table 2 of Regulatory Guide 1.97, Rev. 2, was limited to the dampers required to realign the Control Room Ventilation System for its post-accident emergency ventilation modes. At CPNPP, we have included additional ESF ventilation parameters as accident monitoring variables (See Table 7.5-7B).

18. Table 7.5-7B does not identify which variables are displayed in the Control Room, on the ERF Console, in the TSC or in the EOF as these displays are not required by Reg. Guide 1.97, Rev. 2, Table 2.

19. For Category 2 and 3 non-1E instrumentation, environmental qualification, seismic qualification and quality assurance requirements are not listed if not required by the accident monitoring program. Environmental Qualification is demonstrated in accordance with the requirements of Sections 3.11N and 3.11B for Category 1, 1E instrumentation.

20. QA is provided as necessary to support Environmental Qualification.

21. The containment water level covers the entire range of expected water level (from prior to the start of switchover from injection to recirculation to the maximum containment flood level) in the containment for post-accident conditions. The water level in the sump is assured by the RWST Low-Low level setpoint for the start of switchover. Operator action based on containment water level is not required. Therefore at CPNPP Containment Water Level (NR) is not considered as required for accident monitoring.

22. Since portable instrumentation is primarily used, the fixed radiation monitors perform as backup instrumentation. Therefore Category 3 is appropriate for this variable.

23. Radiation monitoring following an accident is covered by the CPNPP Emergency Plan; Radiation Exposure meters are not required at CPNPP.

24. Position indication is not required in the ERF computer for remote manual valves.

25. See response to the NRC Action Plan developed as a result of the TMI-2 accident, Section III.A.1.2

TABLE 7.5-7C
NOTES AND ABBREVIATIONS FOR TABLES 7.5-7A AND 7.5-7B

(Sheet 3 of 4)

26. These Parameters are D2 variables (1E Devices) as they monitor other systems normally employed for safe shutdown but are not required during or following an accident (Section 7.5.1.1.1). When required to function these instruments are in a mild environment. Environmental qualification is in accordance with Section 3.11B.

27. Technical Specifications require two core exit thermocouples operable per quadrant per train. In the event one or more thermocouple(s) is (are) found inoperable, and as long as the requirements of the Technical Specifications are met, leads of the inoperable thermocouple(s) may be temporarily lifted until the inoperable thermocouple(s) is(are) repaired or replaced.

28. Technical Specifications requires four or more reactor vessel water level sensors operable per channel, one or more in the upper section and three or more in the lower section. In the event, one or more sensor(s) is(are) found inoperable, and as long as the requirements of the Technical Specifications are met, leads of the inoperable sensor(s) may be temporarily lifted until the inoperable sensor(s) is(are) repaired or replaced.

Gen.	-	generator	CVCS	-	Chemical and Volume Control System
WR	-	wide range	N/A	-	not applicable
NR	-	narrow range	MSIV	-	main steam isolation valve
RCS	-	Reactor Coolant System	ECCS	-	Emergency Core Cooling System
Aux.	-	auxiliary	SI	-	Safety Injection
RWST	-	Refueling Water Storage Tank	CR	-	Control Room
CST	-	Condensate Storage Tank	A/C	-	air conditioning
Rad.	-	radiation	Vent	-	ventilation
RHR	-	Residual Heat Removal			
SR	-	source range	EQ	-	Environmentally Qualified As Stated in CPNPP FSAR 3.11
CCW	-	Component Cooling Water	SQ	-	Seismically Qualified as stated in CPNPP FSAR 3.10

TABLE 7.5-7C
NOTES AND ABBREVIATIONS FOR TABLES 7.5-7A AND 7.5-7B

(Sheet 4 of 4)

RCP	-	Reactor Coolant Pump			
Mon.	-	Monitor	AFW	-	Auxiliary feedwater
			QA	-	Quality Assurance Complies As Stated in CPNPP FSAR Chapter 17
ERFCS	-	ERF Console in Control Room			
TSC	-	ERF Console in the TSC	Rad Mon	-	Rad Mon Console in Control Room
EOF	-	ERF Console in the EOF			
Sh.	-	Sheet			

TABLE 7.5-7D
SPECIFIC DEVIATIONS FROM THE GUIDANCE IN REG. GUIDE 1.97, REV. 2

(Sheet 1 of 7)

Variable	Item	R.G. 1.97 Rev. 2	CPNPP	Table 7.5-7E Reference (Justification)
RCS Soluable Boron Concentration	Variable	Required	Not Required	(10)
T(HOT) RCS (WR)	Instrument Range	50°F to 750°F	0-700°F	(1)
T(COLD) RCS (WR)	Instrument Range	50°F to 750°F	0-700°F	(1)
Reactor Vessel Water Level	Instrument Range	Bottom of core to top of Vessel	Upper core plate to top of Reactor Vessel	(1)
Containment Water Level	Instrument Range	Narrow range (sump) Wide range (bottom of containment to 600,000 gal. level)	808'-3”-817'6"	(1)
	Additional Information	Required	Not available	(18)

TABLE 7.5-7D
SPECIFIC DEVIATIONS FROM THE GUIDANCE IN REG. GUIDE 1.97, REV. 2

(Sheet 2 of 7)

Variable	Item	R.G. 1.97 Rev. 2	CPNPP	Table 7.5-7E Reference (Justification)
Containment Isolation Valve Status	Category	1	2	(3)
	Redundancy/Diversity	Required	Not available	(7)
Radiation Level in Circulating Primary Coolant	Category	1	Not Required	(4)
Containment Pressure (WR)	Instrument Range	10 psia to 3x design pressure	0-150 psig	(1)
	Additional information	Required	Not available	(22)
Area Radiation Levels Adjacent Containment	Instrument Range	10^{-1} R/hr to 10^{4} R/hr	10^{-4} to 10^{o} uCi/cc (RE-5637 & X-RE-5702)	(16)
			10^{-1} to 10^{4}mR/hr (XRE-6273 & 6275)	(17)
	Category	2	3	(19)

TABLE 7.5-7D
SPECIFIC DEVIATIONS FROM THE GUIDANCE IN REG. GUIDE 1.97, REV. 2

(Sheet 3 of 7)

Variable	Item	R.G. 1.97 Rev. 2	CPNPP	Table 7.5-7E Reference (Justification)
RHR Heat Exchanger Discharge Temperature	Instrument Range	32°F to 350°F	50-400°F	(1)
SI Accumulator Tank Level	Category	2	3	(5)
	Instrument Range	10% to 90%	0-100%	(1)
	QA and Qualification	Required	Not available	(7)
SI Accumulator Tank Pressure	Instrument Range	0-750 psig	0-700 psig	(1)
Boric Acid Charging Flow	Variable	Required	Not designated as an accident monitoring variable	(9)
Pressurizer Level	Instrument Range	Bottom to top	0-100%	(1)
Pressurizer Relief Tank Temperature	Instrument Range	50°F to 750°F	50-350°F	(1)

TABLE 7.5-7D
SPECIFIC DEVIATIONS FROM THE GUIDANCE IN REG. GUIDE 1.97, REV. 2

(Sheet 4 of 7)

Variable	Item	R.G. 1.97 Rev. 2	CPNPP	Table 7.5-7E Reference (Justification)
Main Steamline Pressure	Instrument Range	From atmospheric to 20% above the lowest safety valve setting	0-1300 psig	(1)
Heat Removal by Containment Fan Heat Removal System	Variable	Required	Not available	(11)
Containment Atmospheric Temperature	Instrument Range	40°F to 400°F	0-360°F	(1)
Containment Sump Water Temperature	Variable	Required	Not available	(12)
High-Level Radioactive Liquid Tank Level	Display	Control Room	Local,Waste processing panels, and CR alarm	(13)

TABLE 7.5-7D
SPECIFIC DEVIATIONS FROM THE GUIDANCE IN REG. GUIDE 1.97, REV. 2

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Variable	Item	R.G. 1.97 Rev. 2	CPNPP	Table 7.5-7E Reference (Justification)
Radioactive Gas Holdup Tank Pressure	Instrument Range	0 to 150% design pressure	0-150 psig	(1)
	Display	Control Room	Local, Waste processing panels and CR alarm	(13)
Main Steamline Radiation	Vent Flow Rate	Required	Release calculated	(14)
Reactor Shield Building Annulus Effluent	Variable	Required (if in design)	Not available (noy in design)	Not in CPNPP design
Condenser Off-gas Radiation	Instrument Range	10^{-6} to 10^{-2} uCi/cc	10^{-5} to 10^{-1} uCi/cc	(1)
Radiation Exposure Meters	Variable	Required	Not available	(15)
Post Accident Sampling System	Variable	Required	Not Required	(10)
Atmospheric Stability	Instrument Range	-5°C to 10°C	-5 to +15°F	(1)

TABLE 7.5-7D
SPECIFIC DEVIATIONS FROM THE GUIDANCE IN REG. GUIDE 1.97, REV. 2

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Variable	Item	R.G. 1.97 Rev. 2	CPNPP	Table 7.5-7E Reference (Justification)
Containment Radiation	Additional Information	Required	Not available	(20)
CST Water Level	Additional Information	Required	Not Available	(21)
CR Area Radiation	Range Category	10^{-1}R/hr to 10^{4}R/hr Category 2	10^{-1}mR/hr to 10^{4}mR/hr Category 3	(1) (6)
PASS Room Area Radiation	Range Category	10^{-1}R/hr to 10^{4}R/hr Category 2	10^{-1}mR/hr to 10^{4}mR/hr Category 3	(1) (6)
Plant Vent Stack Area Radiation	Range Category	10^{-1}R/hr to 10^{4}R/hr Category 2	10^{-1}mR/hr to 10^{4}mR/hr Category 3	(1) (6)
Hot Lab Area Radiation	Range Category	10^{-1}R/hr to 10^{4}R/hr Category 2	10^{-1}mR/hr to 10^{4}mR/hr Category 3	(1) (6)
RHR Pump Room Area Radiation	Category	Category 2	Category 3	(6)

TABLE 7.5-7D
SPECIFIC DEVIATIONS FROM THE GUIDANCE IN REG. GUIDE 1.97, REV. 2

(Sheet 7 of 7)

Variable	Item	R.G. 1.97 Rev. 2	CPNPP	Table 7.5-7E Reference (Justification)
High Level Radioactive Liquid Tank Level	Instrument Range	Top to Bottom	0-100%	(1)
Plant and Environs Radioactivity	Instrument Range	Multichannel gamma-ray spectrometer	Hot Lab NOSF	(23)
CCW Header Temperature	Range	32°F-200°F	30°F-150°F	(2)
Hydrogen Monitors	Category	Category 1	Category 3	(24)

TABLE 7.5-7E
REFERENCE FOR TABLE 7.5-7D

(Sheet 1 of 3)

Supporting justification of alternatives for deviations from the guidance in Reg. Guide 1.97, Rev. 2

(1) These instrument ranges deviate from the specific ranges listed in Table 2 of Reg. Guide 1.97, Rev. 2, but have been found acceptable for CPNPP's specific requirements based on the finding that the CPNPP specified ranges cover the anticipated ranges for normal operation, anticipated operational occurrences and accident conditions.

(2) The highest temperature in the component cooling water header is 136°F. CPNPP selected an upper range of 150°F since it provides a better scale reading on the control board indicator.

(3) Table 2 to Reg. Guide 1.97, Rev. 2, designates the variable, Containment Isolation Valve Position, as category 1 and as a type B variable under Maintaining Containment Integrity. In the CPNPP plant specific analysis (see the CPNPP FSAR, Section 7.5) the key type B variables for Containment Environment are Containment Pressure (NR), Containment Radiation Level, and Containment Water Level. Containment Isolation Valve Status was considered a type C backup variable for monitoring Containment Boundary Integrity. Therefore, Containment Isolation Valve Status is category 2 for CPNPP. Each penetration into the containment has two isolation boundaries.

(4) Table 2 to Reg. Guide 1.97, Rev. 2, designates the variable, Radiation Level in Primary Coolant, as category 1 and as a type C variable under Fuel Cladding. In the CPNPP plant specific analysis (see the CPNPP FSAR, Section 7.5) the type C key variable for monitoring In-Core Fuel Clad integrity is Core Exit Temperature with the primary backup variable Reactor Vessel Water Level Indicating System (RVLIS). Radiation Level in Primary Coolant is not required for CPNPP.

(5) Table 2 to Reg. Guide 1.97, Rev. 2, designates the variable, Accumulator Tank Level, as category 2 and as a type D variable under Safety Injection Systems. In the CPNPP plant specific analysis (see the CPNPP FSAR, Section 7.5) the type D key variables for monitoring ECCS are RWST Level, Safety Injection Pump Flow, RHR Pump Flow, Centrifugal Charging Pump Injection Flow, Containment Water Level, ECCS Valve Status, SI Accumulator Isolation Valve Status, and SI Accumulator Tank Pressure. The backup variable is SI Accumulator Tank Level. Therefore, SI Accumulator Tank Level is category 3 for CPNPP.

(6) Table 2 to Reg. Guide 1.97, Rev. 2, designates the variable, Radiation Exposure Rate, as category 2 and as a type E variable under Area Radiation. Since portable instrumentation is primarily use for this function the fixed radiation monitors perform as backup instrumentation. Therefore, category 3 is appropriate for this variable.

(7) Not required based on the category assigned by the CPNPP plant specific analysis (Refer to Section 7.5).

TABLE 7.5-7E
REFERENCE FOR TABLE 7.5-7D

(Sheet 2 of 3)

(8) NOT USED

(9) Table 2 to Reg. Guide 1.97, Rev. 2, lists the variable, Boric Acid Charging Flow, as a Type D variable under Safety Injection Systems along with the other variables such as Flow in HPI System and Flow in LPI System. The equipment for these three variables at CPNPP are Centrifugal Charging Pump Flow, Safety Injection Pump Flow and RHR Pump Flow. These three variables are included in the CPNPP Accident Monitoring design. For the CPNPP design, Boric Acid Charging Flow is not a measure of Safety Injection and therefore is not an Accident Monitoring variable.

(10) Post Accident Sampling is no longer required for CPNPP in accordance with License Amendment 91.

(11) The CPNPP design does not include a Fan Heat Removal System, inside containment, that is designed to operate following a design basis accident.

(12) The variable, Containment Sump Water Temperature, is not monitored at CPNPP and was not considered a required variable per the CPNPP plant specific accident monitoring analysis (see the CPNPP FSAR, Section 7.5). In addition, it should be noted that diverse information can be obtained by monitoring Containment Atmospheric Temperature, RHR Heat Exchanger Inlet Temperature and RHR Heat Exchanger Discharge Temperature.

(13) The only immediate concern of the Control Room operator following an accident with respect to the level in the High Level Radioactive Liquid Tank and the pressure in the Radioactive Gas Holdup Tank is inadvertently over-filling these tanks. This is prevented by providing an alarm in the Control Room when there is a potential for over-filling one of the tanks.

(14) Table 2 to Reg. Guide 1.97, Rev. 2, includes Vent Flow Rate as a variable to be measured for all identified release points. CPNPP complies with this requirement except for the Steam Generator Relief and Safety Valve discharge path. For this path, Main Steamline Radiation is measured and the volume released is calculated based on the duration for which the valves are open and the physical parameters involved. This is the best way to measure such an intermittent, high energy release.

(15) Radiation Exposure Meters are not required at CPNPP. Radiation monitoring following an accident is covered by the CPNPP Emergency Plan. Issuance of R.G. 1.97, Rev. 3 superseded the errata and deleted this requirement.

(16) An equivalent measure of containment breach is indicated in these areas by means of process (ventilation exhaust) monitors with a range of 10^{-4} to 10^{0} $_{u}$Ci/cc.

TABLE 7.5-7E
REFERENCE FOR TABLE 7.5-7D

(Sheet 3 of 3)

(17) The Spent Fuel Pool area monitors function as normal area monitors in the fuel building. The range of these monitors (10^{-1} to 10^{4}mR/hr) is suitable for monitoring areas adjacent to the containment building.

(18) Containment Water level transmitters were intended to be multipoint sensors which would prevent an ambiguous failure from occurring. The original indicators were never replaced, however, and the original analog indicators rely on an additive logic to compute the water level. This results in the potential for a failed indicator to cause a false reading of ± 1 foot. The containment water level indicators are for information only and will not adversely affect the ability to safety mitigate an accident.

(19) Table 2 to Reg. Guide 1.97 Rev. 2, designates the variable, Area Radiation Levels Adjacent Containment, as Category 2 and as a type C variable under Containment. In the CPNPP plant specific analysis (see the CPNPP FSAR, Section 7.5) the key type C variables for Containment Boundary is Containment Pressure (WR). Adjacent Building Radiation is considered a backup variable for monitoring the Containment Boundary. Therefore this variable is Category 3.

(20) Containment Radiation has redundant channels but additional information in the form of a diverse channel does not exist. Ambiguities can be resolved using portable instruments outside containment and prompt communications to the control room and this will not lead operators to defeat or fail to accomplish a required safety function.

(21) CST Water Level has redundant channels but additional information in the form of another identical channel or a diverse channel does not exist as a qualified display in the control room. Local, such as indication gauge level and pump suction pressure indications are available to resolve ambiguities. Sufficient time is available to resolve ambiguities before the operator must act on CST Water Level Information.

(22) Containment Pressure Wide Range has qualified redundant channels but additional information is not available to resolve ambiguities over the full range of the instruments. The additional information provided by the Containment Pressure Narrow Range is sufficient.

(23) CPNPP field monitoring teams are dispatched, as needed, to collect samples. These samples are transported to the Nuclear Operations Support Facility or the plant Hot Lab for analysis. At either location gamma spectroscophy equipment is used to analyze the samples. Instrumentation provided for this capability meets the intent of Regulatory Guide 1.97, Revision 2.

(24) The Hydrogen Monitors are capable of diagnosing beyond design-basis accidents. The Hydrogen Monitors were changed from Category 1 to Category 3 based on the revision to 10CFR50.44 on October 16, 2003 and License Amendment 117.

TABLE 7.5-7F
GENERAL DEVIATIONS FROM REGULATORY GUIDE 1.97, REV. 2

(Sheet 1 of 2)

Topic	Guidance	CPNPP Design and Justification
Environmental Qualification (EQ)	Regulatory Guide 1.89 and NUREG-0588 (Positions C1.3.1a & C1.3.2a)	EQ at CPNPP is discussed in the CPNPP FSAR, Sections 3.11 and Appendix 3A.
Quality Assurance (QA)	Specific list of regulatory guides(Positions C1.3.1e & C1.3.2d)	The CPNPP Quality Assurance program and the applicable regulatory guides are addressed in the CPNPP FSAR and in particular in Chapter 17.
Operability	1EEE Standard 279 for category 1 (or Tech Specs) (Position C1.3.1d)	CPNPP Operability of Accident Monitoring instrumentation shall be in compliance with the CPNPP Tech Specs.
EQ for category 2 variables	EQ is required for all category 2 variables. (Position C1.3.2a)	Category 2 instrumentation is environmentally qualified when it is subjected to adverse environments caused by the DBA during the time it must serve its intended function. This position is compatible with the EQ rule, 10 CFR 50.49.
Isolation devices	The transmission of signals from Category1 or 2 instrumentation for other than accident-monitoring or systems operation and effluent monitoring should be through isolation devices that are part of the accident monitoring channel and meet the provisions of this Reg. Guide. (Position C1.4a)	The CPNPP design meets this requirement when the power source for the channel is class 1E. The use of Class 1E isolation devices is only justified for Class 1E circuits.

TABLE 7.5-7F
GENERAL DEVIATIONS FROM REGULATORY GUIDE 1.97, REV. 2

(Sheet 2 of 2)

Topic	Guidance	CPNPP Design and Justification
Instrument identification	Type A, B & C category 1 & 2 should be specifically identified (Position C1.4b)	Category 1 and 2, Types A, B and C instrumentation is uniquely identified with the exception of the steam generator blowdown: Condenser-Offgas; and Plant Vent Stack radiation monitors and Containment Isolation Valve (CIV) Status Indication. The radiation monitors are part of a computer based system in which the information is displayed on demand on a LCD. The CIV status indication is provided by control switches and/or monitor light boxes located on the main control board.
Checking, testing, calibration & calibration verification	Comply with Reg. Guide 1.118 (Position C1.4h)	Compliance with Reg. Guide 1.118 is as discussed in Section 1A(B) of the CPNPP FSAR. The surveillance requirements for accident monitoring channels will comply with the CPNPP Tech. Specs. as implemented by CPNPP test procedures (see FSAR Section 13.5.2.2.5).

7.6 ALL OTHER INSTRUMENTATION SYSTEMS REQUIRED FOR SAFETY

7.6.1 INSTRUMENTATION AND CONTROL POWER SUPPLY SYSTEM

7.6.1.1 Description

The following is a description of the Instrumentation and Control Power Supply System (also referred to as the Class 1E 118V AC Uninterruptible Power System, see Section 7.1.1):

1. Refer to Figure 8.3-15 for a single line diagram of Class 1E, 118V AC Instrumentation and Control Power Supply System.

2. There are four Class 1E inverters per train, two for the reactor protection system and the other two for the balance of plant systems. Each inverter is connected independently to one Class 1E distribution panel. In addition to the above, there is one spare installed inverter per train. The spare inverter can be aligned to substitute any of the four inverters in that train. Procedural controls and interlocks ensure that the spare inverter can feed the loads of only one inverter at a time and the power source of the spare inverter is the same as of the substituted inverter. This is accomplished using the selector switches provided on the inverters.

3. The inverters provide a source of 118V, 60 hertz (Hz) grounded uninterruptible power for the operation of the Reactor Protection System instrumentation and other 118 VAC system vital loads. To assure continued operation of the 118V Class 1E AC System, the incoming power to the inverters is provided by the Class 1E DC switchboards. The Class 1E DC switchboards are normally powered from the 480V AC system via the battery chargers and in case of loss of battery chargers or station blackout, the station batteries feed the DC switchboards and the inverters. Each inverter is provided with a 120V AC bypass source. In case of UPS failure or fault condition the transfer of load from the inverter to the bypass source takes place automatically.

4. Each of the above distribution panels is also provided with a 120V AC backup source. Mechanically interlocked, transfer circuit breakers are provided in the distribution panels to prevent paralleling the inverters with the backup source.

5. For the power supply system for the balance of plant furnished nonsafety-related instrumentation and additional details of Class 1E UPS system, refer to Section 8.3.1.

7.6.1.2 Analysis

There are two Class 1E batteries and four battery chargers per train. One battery charger and a spare are provided for each battery. Each battery is attached to a bus serving one Reactor Protection System inverter and one BOP System inverter. Channel I & Channel III RPS inverters are powered by Train A and Channel II & Channel IV RPS inverters are powered by Train B. In addition, there is one spare installed inverter per train that can be manually aligned to feed the loads of any inverter in that train. Procedural controls and interlocks ensure that the spare inverter can feed the loads of only one inverter at a time and the power source of the spare inverter is the same as of the substituted inverter.

Since one BOP inverter and one RPS inverter is connected to one DC bus in each train, therefore the loss of a single DC bus can only affect one of the four RPS inverters and one of the four BOP system inverters. Each inverter is independently connected to its respective distribution panel, so the loss of an inverter cannot affect more than its associated distribution panel. In case of loss of an inverter the spare inverter can be manually aligned to feed the loads of the out of service inverter.

In addition, two independent sources (one independent source per train) of backup 120V AC power are provided to the inverter panels. Four of the eight distribution panels are connected to each source. Each distribution panel can receive power from the 120V AC backup source under operator control. The mechanically interlocked, transfer circuit breakers are provided in the distribution panels to prevent paralleling the inverter with the backup source.

Therefore no single failure in the Instrumentation and Control Power Supply System or its associated power supplies can cause a loss of power to more than one of the redundant channel loads and one of vital bus loads.

The inverters are designed to maintain their outputs within acceptable limits. The loss of DC input is alarmed in the control room, as is the loss of an inverter output. Inverter DC input and AC output breakers have local controls only. There are no inverter breaker controls on the control board as no manual action is required for the switch over to the DC battery source if there were loss of 480V AC power sources to the battery charger. Upon loss of battery chargers the inverters are automatically powered from the station batteries.

Physical separation and provisions to protect against fire are discussed in Chapter 8.

Based on the scope definitions presented in References [1] through [3], the criteria which are applicable to the Instrumentation and Control Power Supply System is the Institute of Electrical and Electronic Engineers (IEEE) Standard 308-1974. The design is in compliance with IEEE Standard 308-1974 and Regulatory Guide 1.32. Availability of this system is continuously indicated by the operational status of the systems it serves (see Figure 8.3-15) and is verified by periodic testing performed on the served systems. The inverters have been seismically qualified as discussed in Section 3.10B.

7.6.1.3 Control System Failures

The following evaluation consists of postulating failures which affect the major NSSS control systems and demonstrating that for each failure, the resulting event is within the bounds of existing accident analyses. The events which are considered are:

1. Loss of any single instrument

2. Break of any single instrument line

3. Loss of power to all system powered by a single power supply system (i.e. single inverter)

The analysis is conducted for all five major NSSS control systems:

1. Reactor control system

2. Steam dump system

3. Pressurizer pressure control system

4. Pressurizer level control system

5. Feedwater control system

The initial conditions for the analysis are assumed to be anywhere within the full operating power range of the plant (i.e. 0-100%) where applicable.

The results of the analysis indicate that, for any of the postulated events considered in a) through c) above, the condition II accident analyses given in Chapter 15 of the Comanche Peak FSAR are bounding.

7.6.1.3.1 Loss of Any Single Instrument

TABLE 7.6-1 Loss of Any Single Instrument, is a sensor-by-sensor evaluation of the effect on the control systems itemized above caused by a sensor failing either high or low. The particular sensor considered is given, along with the number of channels which exist, the failed channel, the control systems impacted by the sensor, the effects on the control systems for failures in both directions, and the bounding FSAR accident. Where no control action occurs or where control action is in a safe direction, no bounding accident is given.

The table clearly shows that for any single instrument failure, either high or low, the condition II events itemized in the FSAR Chapter 15 are bounding.

7.6.1.3.2 Loss of Power to an Inverter, Control Group, or Protection Set

The Comanche Peak NSSS instrument power supply consists of four instrument distribution panels 1PC1, 1PC2, 1PC3 and 1PC4 receiving power through four inverters (for convenience called inverters I through IV). Each instrument distribution panel powers a single control group and a single protection set (panel 1PC1, powered by inverter I, distributes power to control group I and protection set I; panel 1PC2, powered by inverter II, distributes power to control group 2 and protection set II, etc.). In addition, each control group cabinet receives a backup power from a non-safety instrument distribution panel. Therefore, a loss of a single inverter can cause only the loss of one protection set; the backup power supply, through auctioneering will continue to supply power to the control-grade cabinets. However, this backup power is not available for control grade functions requiring 118VAC power. Tables 7.6-2 through 7.6-5, Loss of Power to Protection Sets I through IV, respectively, analyze the effects on the control systems caused by the loss of power to a single inverter. Identical arrangement applies to Unit 2. In the tables, the control systems affected, the sensors affected, the failure direction, the effect on the control systems, and the bounding FSAR accident are given. Where no control action occurs or where control action is in a safe direction, no bounding accident is given.

All of the above described inverters, control groups, and protection sets are unique to the NSSS. In addition, there are four Class 1E and four non-Class 1E static uninterruptible power supplies for the Balance of Plant (BOP) control system and sensor power. In the absence of inverter output of these power supplies, the static switch automatically disconnects the inverter from the load and connects the load to an alternate power supply. This design ensures uninterruptible power supply for the BOP safety and non-safety-related control systems and sensors.

Besides the loss of power to a protection set, there is the chance of having an electrical fault on one of the control system circuit cards. The control systems are designed so that each card is used in only one control system. A circuit card failure cannot directly impact more than one control system. A failure on a control card would cause the controller to generate either an "off" or a "full on" output, depending on the type of failure. This result would be similar to having a fault in a sensor feeding the control system. Therefore, the failure of or loss of power in any control system circuit card would be bounded by the Loss of Any Single Instrument analysis described in Table 7.6-1.

The tables show that for a loss of power to any protection set, the Condition II events analyzed in the FSAR Chapter 15 are bounding.

7.6.1.3.3 Loss of Common Instrument Lines

Table 7.6-6, Loss of Common Instrument Lines, considers the scenario whereby an instrument line which supplies more than one signal ruptures, causing faulty sensor readings.

Two sets of sensors are located in common lines:

1. Loop steam flow (control groups 1 through 4 for steam generators 1 through 4, respectively) and narrow range steam generator level (protection set II, any steam generator)

2. Pressurizer level (protection sets, I, II, or III) and pressurizer pressure (protection sets I, II, III, or IV)

Not shown on the tables since they are not part of the control system but are used just for protection are the loop flow transmitters. There are three flow transmitters in each loop, with each transmitter having a common high pressure tap but separate and unique low pressure taps. Therefore, a break at the high pressure flow transmitter tap would result in disabling all three flow transmitters in one loop, resulting in a low flow reading for all three transmitters. This would result in a reactor trip if the plant is above the P-8 setpoint, or an annunciation if it is below P-8.

The only malfunctions mode explicitly analyzed was a break in the common instrument line at the tap. Another possibility is to have a complete blockage in the sensor tap, causing the sensor to read a constant (before blockage) value. However, this last failure mode is not analyzed since it is really not a credible event. There is no anticipated agent available that would cause a tap blockage. The Reactor Coolant System piping and fittings, and the instrument impulse line tubing are all stainless steel, so no products of corrosion are expected. Also, the water chemistry is of high quality, which along with high temperature operation, precludes the presence of solids in the water and assures the maintenance of the solubility of chemicals in the water. Therefore, the hypothesis of the presence of a complete blockage of the sensor tap is not sufficiently credible to warrant its consideration as a design basis.

In the extremely unlikely event that a complete instrument line blockage were to occur, the condition is detectable because the reading would become static (no variations over time). In an unblocked channel, a reading would always vary somewhat due to noise (i.e. flow induced noise in flow channels) or slight controller action (i.e. cycling operation of spray and heaters in pressurizer). By a comparison of the static channel to the redundant unblocked channels, the operator would be informed that a blockage in one channel has occurred.

7.6.2 RESIDUAL HEAT REMOVAL ISOLATION VALVES

7.6.2.1 Description

The Residual Heat Removal System (RHRS) isolation valves are normally closed and are only opened for residual heat removal after system pressure is reduced to approximately 425 pounds per square inch gage (psig) and system temperature has been reduced to approximately 350°F. They are the same type of valve and motor operator as those used for accumulator isolation, but they differ in their controls and in their indications in the following respect.

The residual heat removal valves are provided with red (open) and green (closed) position indicating lights located at the control switch for each valve. These lights are powered by valve control power and actuated by valve motor operator limit switches.

There are two motor operated valves in series in each of the two RHR pump suction lines from the Reactor Coolant System (RCS) hot legs. The two valves nearest the RCS (8702A, B) are designated as the inner isolation valves, while the two valves nearest the RHR pumps (8701A, B) are designated as the outer isolation valves. The interlock features provided for the outer isolation valves, shown on Figure 7.6-2, Sheet 1 are identical to those provided for the inner isolation valves, shown on Figure 7.6-2, Sheet 2.

Different types of pressure transmitters are used in the inner and outer isolation valve interlocks to provide the required diversity. One is a Veritrak Model 76 (PH2) while the other is a Rosemount Model 1154 SH.

Each valve is interlocked so that it cannot be opened unless the RCS pressure is below approximately 425 psig. This interlock prevents the valve from being opened when the RCS pressure plus the RHR pump pressure would be above the RHRS design pressure.

7.6.2.2 Analysis

Based on the scope definitions presented in References [2] and [3], these criteria do not apply to the residual heat removal isolation valve interlocks; however, in order to meet NRC requirements and because of the possible severity of the consequences of loss of function, the requirements of IEEE Standard 279-1971 will be applied with the following comments.

1. For the purpose of applying IEEE Standard 279-1971, to this circuit, Protection System is defined as the two valves in series in each line and all components of their interlocking circuits.

2. IEEE Standard 279-1971, Section 4.10

The above mentioned pressure interlock signals and logic will be tested online to the maximum extent possible without adversely affecting safety. This test will include the analog signal through to the train signal which activates the slave relay (the slave relay provides the final output signal to the valve control circuit). This is done in the best interests of safety since an actual actuation to permit opening the valve could potentially leave only one remaining valve to isolate the low pressure RHRS from the RCS.

3. IEEE Standard 279-1971, Section 4.15

This requirement does not apply, as the setpoints are independent of mode of operation and are not changed.

Environmental qualification of the valves and wiring are discussed in Section 3.11N.

7.6.3 REFUELING INTERLOCKS

7.6.3.1 Instrumentation Installed to Prevent Refueling Accidents

7.6.3.1.1 Initiating Circuits

The Fuel Handling System operates under manual local control. The refueling interlocks operation is completely automatic and stops any action by the operator that could be detrimental to the system.

7.6.3.1.2 Logic

Refer to Section 9.1.4.3.1 for a description of the refueling interlock logic.

7.6.3.1.3 Interlock Bypasses

1. Fuel Transfer System

There are three interlock bypasses in the Fuel Transfer System.

a. Transfer Car Permissive Switch Interlock Bypass - The refueling canal upender (lifting arm) is interlocked with the manipulator crane (refueling machine). The upender cannot be operated unless the manipulator crane gripper tube (mast) is in the fully retracted position or the crane is over the core. The bypass control for this interlock is located on the Fuel Transfer System reactor side control console. The upender on the Fuel Building side is similarly interlocked with the fuel handling bridge crane with bypass control located on the Fuel Transfer System Fuel Building side control console.

b. Transfer Car Lifting Arm Interlock Bypass - The transfer car is interlocked with both upenders such that both upenders must be in the down position before the transfer car can be moved. The bypass for this interlock is located on the Fuel Transfer System Reactor and Fuel Building side control consoles.

c. Lifting Arm Transfer Car Position Interlock Bypass - The conveyor interlock allows upender operation only when the transfer car is at either end of its travel. The bypass for this interlock is located on both control consoles.

2. Manipulator Crane (Refueling Machine)

There are six interlock bypasses on the manipulator crane. The control switches for these bypasses are located on the manipulator crane control console.

a. Overload Bypass - The hoist master switch up circuit is interlocked with a load cell contact which opens when the load on the hoist is greater than 250 pounds above the indicated suspended weight for wet conditions. This load cell contact can be bypassed by the overload bypass switch.

b. Hoist Interlock Bypass - The hoist-gripper position interlock consists of two separate circuits that work in tandem such that one circuit must be permissive for the hoist to operate. This criteria can be eliminated by the hoist interlock bypass switch.

c. Bridge Left Interlock Bypass and

d. Bridge Right Interlock Bypass - These interlock bypasses allow the bridge to operate beyond its travel limit switches.

e. Trolley Interlock Bypass - This interlock bypass allows the trolley to operate beyond it travel limit switches.

f. Gripper Up Disengaged Bypass - Providing a fuel assembly is not attached to the gripper, bridge and trolley movement is allowed without the gripper tube being in the maximum up position by bringing it up approximately 12 inches into the outer mast. The gripper up disengaged bypass allows the gripper tube to be raised to the full up position and allows bridge and trolley movement only if the gripper tube is in the maximum up position.

7.6.3.1.4 Interlocks, Redundancy

In the analysis below, the refueling interlocks have only been analyzed for failure in the permissive mode. The consequences of interlock failure in the interlocked mode are the same for all; the failed interlock would prevent normal operation of the equipment until repaired. There is no case where failure in the interlocked mode can result in a hazardous situation.

The manipulator crane electrical interlocks are as listed in Section 9.1.4.3.1

1. Travel Limit Switches on Bridge and Trolley

Failure of travel limit switches in the permissive mode could result in collision of the mast with the canal walls, vessel guide studs or the upper internals in their stored position. The fuel assembly would be protected from damage by the outer mast. The mast is a 16 inch diameter, 3/4 inch wall pipe that completely encloses the fuel. Within the mast, the fuel is

restrained by guide bars at all four corners that limit the lateral movement of the fuel to 1/4 inch maximum and supports it along its length.

2. Bridge, Trolley and Hoist Drive Mutual Interlocks

   These interlocks are redundant and satisfy the single failure criterion.

3. Bridge Trolley Drive - Gripper Tube Up

   This interlock is redundant and satisfies the single failure criterion.

4. Gripper Interlock

   This interlock is redundant and satisfies the single failure criterion.

5. Excessive Suspended Weight

   This interlock is redundant and satisfies the single failure criterion.

6. Hoist-Gripper Position Interlock

   The hoist-gripper position interlock consists of two separate circuits that work in tandem such that one circuit must be permissive for the hoist to operate. The interlock has a self monitoring circuit such that if one or both interlocking circuits fail in the permissive mode an audible and visual alarm on the console is actuated. The interlock, therefore, is not redundant but does satisfy the single failure criterion since both an interlocking circuit and the monitoring circuit must fail to cause a hazardous condition.

7. Bridge - Trolley Drive Interlock

   This interlock is part of the travel limit switch circuits described in (a).

8. Bridge and Trolley Hold-down devices are not properly defined as interlocks. They are utilized in the seismic restraint of the bridge and trolley.

The fuel transfer system interlocks are as listed in subsection 9.1.4.3.1

1. Transfer Car - Transverse Interlock

   This interlock satisfies the single failure criterion. The interlock is primarily designed to protect the equipment from overload and possible damage.

   Assuming the interlock fails in the permissive mode, there are two accidents to be considered. First, the lifting frame in the transfer canal is up or partially up and the car is driven towards the position. The car passes under the frame and is stopped by a mechanical stop at the upending position. The second case assumes that the fuel container is in the upright position in the Containment and the conveyor car permissive switch circuit fails in the permissive condition. The car is mechanically held in the frame and remains in the upright position. Movement is permitted only when the fuel container is in the full down position.

2. Lifting Arm - Transfer Car Position Interlock

   This interlock is redundant and satisfies the single failure criterion.

3. Transfer Car - Valve Open Interlock

   This interlock does not satisfy the single failure criteria. If the interlock fails in the permissive mode, the car can be started with the valve not fully open. The conveyor car contacts the valve gate stopping the conveyor car movement. As soon as the valve is opened fully, the conveyor car is freed.

4. Lifting Arm - Manipulator Crane Interlock

   This interlock is redundant and satisfies the single failure criteria.

5. Lifting Arm - Fuel Handling Bridge Crane (Fuel Handling Machine) Interlock

   This interlock satisfies the single failure criteria.

7.6.3.1.5 Actuated Devices

The only device actuated on an interlock failure is the gripper interlock failure alarm horn located on each of the crane control consoles. This alarm occurs when the gripper engaged and gripper disengaged limit switches are both closed or both open.

7.6.3.1.6 Design Bases Information

1. Design Bases

   The design bases for the portions of the Fuel Handling System important to safety is to provide the necessary interlocks, controls, and alarms to prevent fuel assembly damage during refueling operations. Refer to Section 9.1.4.3 for a description of the provisions made to ensure safe handling of the fuel assemblies.

2. Conformance to IEEE 279-1971

   These interlocks are not specifically designed to meet IEEE 279-1971 since the scope of IEEE-279, which is for the Station Protection System, does not apply to the Fuel Handling System.

   The Station Protection System, as explained in the IEEE-279 scope section, includes signals, such as those which actuate Reactor Trip and engineered safety features, which are all those that protect the plant during normal power operation. It should be noted that the Fuel Handling System is not operational during normal plant operation and is therefore not categorized as a Nuclear Power Generating Station Protection System.

7.6.3.2 Analysis

7.6.3.2.1 NRC General Design Criteria

Implementation of the requirements of NRC General Design Criteria is described in Section 3.1.

7.6.3.2.2 Single Failure Criterion

See Section 7.6.3.1.4 entitled “Interlocks, Redundancy” above.

7.6.3.2.3 Conformance to Branch Technical Positions ISCB 3, 4, and 20

Information related to conformance with Branch Technical Positions may be found by reference in Table 7.1-3.

7.6.3.3 Instrumentation Installed to Mitigate the Consequences of Refueling Accidents

7.6.3.3.1 Description

The instrumentation installed to mitigate the consequences of refueling accidents is included in the Area Radiation Monitoring System (ARMS). A detailed discussion of the ARMS is contained in Section 12.3.

7.6.3.3.2 Analysis

The analyses of effects and consequences of the postulated fuel handling accidents in Section 15.7.4 do not take any credit for the instrumentation installed to mitigate the consequences of these accidents. With no credit taken for this instrumentation, the calculated doses from these accidents are well below the limits defined in 10 CFR 100.

7.6.4 ACCUMULATOR MOTOR OPERATED VALVES

The design of the interconnecting of these signals to the accumulator isolation valve meets the criteria established in Nuclear Regulatory Commission (NRC) Branch Technical Position EICSB-4 on this matter. However, some provisions of the BTP are no longer applicable as noted below.

1. Automatic opening of the accumulator valves is not required. Technical Specifications require the isolation valves to be open with power removed above 1000 psig.

2. Visual indication in the control room of the open or closed status of the valve. (Refer to Section 6.3.5.5)

3. Bypassed and inoperable status indication in accordance to regulatory Guide 1.47 is not required because the valves are not allowed to be closed when required operable by technical specifications. (Refer to Section 7.1.2.6)

4. Utilization of a safety injection signal to automatically remove (override) any bypass features that are provided is not required because the Technical Specifications require the isolation valves to be open with power removed above 1000 psig.

The valves are not required to meet the above BTP requirements; however, the current control circuit for these valves (functional block diagram of valves 8808A, B, C, and D) is still as shown on Figure 7.6-3. The valves and control circuits are further discussed in Sections 6.3.2.2.11 and 6.3.5.

In order to comply with NRC Branch Technical Position EICSB-18, power is removed from the accumulator discharge valves when the valves are required open by Technical Specifications.

The four main control board position switches for these valves provide a “spring return to auto” from the open position and a “maintain position” from the closed position.

The “maintain closed” position is not used in MODES 1-3 above 1000 psig nor is it used for meeting fire protection requirements during shutdown.

During plant shutdown, the accumulator valves are in a closed position. To prevent an inadvertent opening of these valves due to a fire during that period the accumulator valve breakers are opened or removed. Administrative control is again required to ensure that these valve breakers are closed during the pre-startup procedures.

These normally open motor operated valves have alarms, indicating a malpositioning (with regard to their Emergency Core Cooling System function during the injection phase). The alarms sound in the control room.

An alarm will sound for either accumulator isolation valve under the following conditions when the RCS pressure is above the “SI unblocking pressure.”:

1. Valve motor operator limit switch indicates valve not open.

2. Valve stem limit switch indicates valve not open. The alarms on this switch will report itself at given intervals.

7.6.5 SWITCHOVER FROM INJECTION TO RECIRCULATION

The details of achieving cold leg recirculation following safety injection are given in Section 6.3.2.8 and on Table 6.3-7. Figure 7.6-4 shows the logic which will be used to open automatically the sump valves.

The logic functions derived from the refueling water storage tank level sensors are depicted in Figure 7.6-4, Sheet 1.

As noted in Section 6.3.2.8, protection logic is provided to open automatically the two Safety Injection System (SIS) recirculation sump isolation valves (8811A and 8811B) when two of four (2/4) Refueling Water Storage Tank (RWST) level signals are less than the Lo-Lo level setpoint in conjunction with the initiation of the engineered safety features actuation signal (“S” signal). The 2/4 Lo-Lo RWST level is the trip signal shown on Fig. 7.6-4, Sheet 1.

This automatic action would align the two residual heat removal pumps to take suction from the containment sump and to deliver directly to the RCS. The automatic action, which bypasses the blocks preventing operator opening valves during normal operation, is shown on Figure 7.6-4, Sheet 2, as a coincidence logic function of the Trip signal, the main control board switch in the

auto position (which is designed to be spring return to this position), and the presence of the "S" signal. The design provides for the retention of the "S" signal, should one be generated, that allows for this automatic changeover. The "S" signal is retained by sealing it in (i.e., it is latched). The retention of this signal is necessary since emergency procedures are written to permit the operator (by means of the manual (S.I.) reset and block signal, shown on Fig. 7.2-1, Sheet 8) to reset the "S" signal at a time significantly in advance of the RWST Lo-Lo water level signal generation that initiates the changeover. However, if this has not occurred prior to Lo-Lo, it is performed as part of ECCS transfer. A manual reset pushbutton is provided on the main control board to permit the operator to remove the actuation signal in the event the corresponding sump isolation valve must be closed and retained in a closed position following a LOCA, such as, for maintenance purposes.

The Trip Signal logic consists of four RWST water level transmitters, each of which provides a level signal to one of the four RWST level channel bistables. The RWST level channel bistables are:

1. normally de-energized

2. de-energized on loss of power

3. energized on Lo-Lo setpoint

Each level channel bistable is assigned to a separate instrumentation and control power supply. A trip signal is provided from both Train A and Train B Solid State Protection System (SSPS) cabinets to the corresponding sump isolation valve's logic, should two of the four water level channel bistables receive a RWST level signal lower than the Lo-Lo level setpoint following the generation of an S signal.

On-line test provisions are designed such that the test operator cannot open the sump isolation valves unless the corresponding RWST/RHR suction isolation valves are closed and either the corresponding RHR inner or outer isolation valves are closed. The test button (TB) signal is, therefore, blocked from simulating the 2/4 RWST low water level signal until the above is accomplished.

The recirculation sump isolation valves are also interlocked such that they must be closed before the following valves can be opened:

1. RWST/RHR pump suction isolation valves, 8812A and 8812B.

2. RHR inner or outer isolation valves 8701A, 8701B, 8702A, and 8702B.

A lo-lo, two-out-of-four, RWST level signal is provided for automatic change-over from injection mode to recirculation mode, as described in Table 6.3-7. RWST depletion due to injection and changeover to recirculation mode is discussed in Section 6.3.

An RWST empty level alarm is provided to the operator to communicate the need to initiate pump protection by stopping any ECCS pumps still taking suction. The RWST "empty" level alarm has a ±2.3 percent uncertainty band. This is the maximum loop uncertainty including process measurement accuracy.

The operator has the following status indication information available in the control room to guide manual switch over of the CSS from the RWST to the containment sumps:

RWST lo-lo level alarm (any of 4-channels)

RWST empty alarm (any of 4-channels)

RWST level indicator (See Section 7.5)

See Sections 6.2.2 and 6.5 for the design bases, system design, design evaluation, tests and inspection, and instrumentation requirements of the CSS.

7.6.6 PROCESS AND EFFLUENT RADIOLOGICAL MONITORS

Seismic design, redundancy and emergency power for process and effluent radiological monitors are discussed in Section 11.5.

7.6.7 REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS

7.6.7.1 Description

The leakage detection systems will be intended to sense radioactive and nonradioactive leakage from the reactor coolant and auxiliary loops.

Means will be available to locate the leakage, and if necessary, corrective actions will be taken to ensure that total leakage is below levels consistent with safe operation of the plant.

7.6.7.1.1 Leakage Detection Methods

The methods for detecting leakage to the containment are by containment air particulate monitors, radioactive gas monitors, specific humidity monitors and sump level control and flow monitors. Refer to the description of these methods in Section 5.2.5.

7.6.7.1.2 Instrumentation and Controls

1. Containment air particulate monitors

   Indication, recording and high radiation alarm are provided in the control room.

2. Radioactive gas monitors

   Indication, recording and high radiation alarm are provided in the control room.

3. Specific humidity monitors

   High level and high rate of level increase alarms are provided for the condensate measuring systems.

   Indications and plant process computer inputs for the dew point temperature monitoring system are provided in the control room.

4. Sump level control and flow monitors

   The containment sump pumps are automatically controlled by mechanical alternators on a pre-determined increasing level. One sump pump will start and continue to run until a pre-determined decreasing low level. The second sump pump will start if, with one pump operation, the sump level continues to increase. These conditions were alarmed in the control room. Pumps status indication is provided in the control room. Pump discharge flow is recorded in the control room.

7.6.7.2 Analysis

The Reactor Coolant Pressure Boundary Leakage Detection System is formed by four diverse systems. The containment air particulate monitor is qualified to function through the Safe Shutdown Earthquake.

The system is in accordance with 10CFR50, General Design Criterion 30, Regulatory Guide 1.45 as discussed in Section 1A(B) and IEEE Standard 279-1971, Section 4.l0.

7.6.8 INTERLOCKS FOR RCS PRESSURE CONTROL DURING LOW TEMPERATURE OPERATION

The basic function of the RCS pressure control during low temperature operation is discussed in Section 5.2.2. As noted in Section 5.2.2, this pressure control includes automatic actuation logic for two pressurizer power operated relief valves (PORV's). The function of this actuation logic is to continuously monitor RCS temperature and pressure conditions, with the actuation logic only unblocked when plant operation is at a temperature below the Reference Nil Ductility Temperature (RNDT). The monitored system temperature signals are processed to generate the reference pressure limit program which is compared to the actual monitored RCS pressure. This comparison will provide an actuation signal to an actuation device which will cause the PORV to automatically open if necessary to prevent pressure conditions from exceeding allowable limits. See Figure 7.6-5 for the block diagram showing the interlocks for RCS pressure control during low temperature operation. As shown on this figure, the generating station variables required for this interlock are channelized as follows:

1. Protection Set I

   a. Wide Range RCS Temperature from Hot Legs 1 & 2

   b. Wide Range RCS Temperature from Cold Legs 3 & 4

   c. Wide Range RCS System Pressure (PT 405)

2. Protection Set II

   a. Wide Range RCS Temperature from Cold Legs 1 & 2

   b. Wide Range RCS Temperature from Hot Legs 3 & 4

3. Protection Set IV

a. Wide Range RCS System Pressure (PT 403)

The wide range temperature signals, as inputs to the Protection Sets I and II, continuously monitor RCS temperature conditions whenever plant operation is at a temperature below the RNDT. In Protection Set I, the existing RCS cold and hot leg wide range temperature channels will supply continuous analog input through an isolator to two auctioneering devices, which are located in the Control Group No 1.

The lowest reading as selected by one auctioneer is input to a function generator which calculates the reference pressure limit program considering the plant's allowable pressure and temperature limits. Also available from Protection Set I is the wide range RCS pressure signal which is sent through an isolation device to Control Group 1. The reference pressure from the function generator is compared to the actual RCS pressure monitored by the wide range pressure channel. The error signal derived from the difference between the reference pressure and the actual measured pressure will first annunciate a main board alarm whenever the actual measured pressure approaches, within a predetermined amount, the reference pressure. On a further increase in measured pressure, the error signal will generate an annunciated actuation signal. The actuation signal available from Auxiliary Relay Rack "A" will control PORV "A" whenever a temperature-dependent permissive signal from Process Control Group 4 is present. The two auctioneer devices mentioned above select the lowest temperature. One low temperature is used as a permissive; the other, for use in the reference pressure limit program. The temperature-dependent permissive to the PORV's actuation device effectively disarms (blocks) the actuation signal at temperatures greater than the range of concern. This will prevent unnecessary system actuation when at normal RCS operating conditions as a result of a failure in the process sensors.

The monitored generating station variables that generate the actuation signal for the "B" PORV are processed in similar manner. In the case of PORV "B", the reference temperature is generated in Process Control Group 4 from the lowest auctioneered wide range cold or hot leg temperature; the auctioneering device deriving its input from the RCS wide range temperature in Protection Set II and the actual measured pressure signal is available from Protection Set IV. Therefore, the generating station variables used for PORV "B" are derived from a Protection Set that is independent of the sets from which generating station variables used for PORV A are derived. The error signal derivation itself used for the actuation signals is available from the control group.

Upon receipt of the actuation signal, the actuation device will automatically cause the PORV to open. Upon sufficient RCS inventory letdown, the operating RCS pressure will decrease, clearing the actuation signal. Removal of this signal causes the PORV to close.

7.6.8.1 Analysis of Interlock

Many criteria presented in IEEE-279-1971 and IEEE-338-1971 standards do not apply to the interlocks for RCS pressure control during low temperature operation, because the interlocks do not perform a protective function but rather provide automatic pressure control at low temperatures as a backup to the operator. However, although IEEE-279 criteria do not apply, some advantages of the dependability and benefits of an IEEE-279 design have accrued by including selected elements as noted above in the protection sets and by organizing the control

of two (either of which can accomplish the RCS pressure function) into dual channels wherever practical. Either of the two PORV's can accomplish the RCS pressure control function.

The design of the low temperature interlocks for RCS pressure control is such that pertinent features include:

1. No credible failure at the output of the protection set racks, after the output leaves the racks to interface with the interlocks, will prevent the associated protection system channel from performing its protective function because such outputs that leave the racks go through an isolation device as shown in Figure 7.6-5.

2. Testing capability for elements of the interlocks within (not external to) the Protection System is consistent with the testing principles and methods discussed in Section 7.2.2.2.3.10. It should be noted that there is an annunciator which provides an alarm when there is low auctioneered RCS temperature (below RNDT) coincident with a closed position of the motor operated (MOV) pressurizer relief isolation valve. This MOV is in the same fluid path as the PORV, with a separate MOV used and alarmed associated with the second PORV.

3. A loss of offsite power will not defeat the provisions for an electrical power source for the interlocks because these provisions are through onsite power which is described in Section 8.3.

7.6.9 MONITORING COMBUSTIBLE GAS IN THE CONTAINMENT

The primary means of measuring the concentration of combustible gases in the Containment following a severe accident is by the Containment Hydrogen Monitoring.

Section 6.2.5 provides a description of the Containment Combustible Gas Control .

7.6.10 FIRE DETECTION SYSTEM

The fire detection system along with the fire-extinguishing system are part of the Fire Protection System discussed in Section 9.5.1.

7.6.11 INSTRUMENTATION FOR MITIGATING CONSEQUENCES OF INADVERTENT BORON DILUTION

7.6.11.1 Description

Instrumentation is provided to mitigate the consequences of inadvertent addition of unborated, primary grade water into the Reactor Coolant System.

Figure 7.6-6 is a simplified system block diagram showing the flux doubling detection system (2 ϕ meter) and the protection system output for isolation valve actuation.

In the event of a boron dilution transient, the Nuclear Instrumentation Source Range in conjunction with the 2 ϕ meter will detect a doubling of the neutron flux. This information is sent to the Solid State Protection System. An alarm is sounded at the time for plant operators to indicate that flux doubling has occurred.

7.6.11.2 Analysis

The analysis of effects and consequences of inadvertent boron dilution transients is covered in Section 15.4.6.

7.6.11.3 Qualification

Qualification of the instrumentation is discussed in Sections 3.10 and 3.11.

7.6.12 MITIGATION OF ENVIRONMENTAL EFFECTS OF PIPE BREAKS OUTSIDE CONTAINMENT

An environmental analysis of the compartments outside containment as a result of pipe breaks was performed for CPNPP Units 1 & 2, as described in Section 3.6. The results showed that with detection and mitigation added for three systems, Auxiliary Steam (SA), Steam Generator Blowdown (SGB) and Chemical Volume and Control (CVCS), minimal environmental effects would be imposed on the safety-related and non-safety related equipment and structures required for safe shutdown.

From the analysis, the environmental conditions of the equipment required for shutdown was identified. Alternate shutdown paths were evaluated when essential equipment was not qualified for the harsh environmental conditions. Where alternate shutdown paths could not be found, mitigation of the pipe break as described below was used to insure an adequate environment for equipment required for safe shutdown.

7.6.12.1 Auxiliary Steam System Line Break Mitigation

Two (2) redundant Auxiliary Steam pressure switches are provided for each of two (2) Auxiliary Steam header lines where the break is postulated to occur. These pressure switches (X-PS-3226A, 3226B, 3227A, 3227B) are located remote from the environment resulting from the postulated Auxiliary Steam line break. These switches, shown on Figure 10.4-16 (Sh.3), are Non-Class 1E and Non-Seismic Category I. See Section 10.4.13 for a description of the Auxiliary Steam System. The isolation valves, shown on Figure 10.4-16 (Sh.2), are also Non-Class 1E and Non-Seismic Category I.

Instrument air (non-Class 1E, non-seismic category I) and offsite power are essential for auxiliary steam system line break mitigation.

Tabulated below are the major sources of steam to the Auxiliary Steam System and their isolation valves.

		Isolation Valves
	Steam Source (Located Upstream of Pipe Breaks)	
1.	Main Steam (Unit 1 or 2) or Aux. Boiler	2 in Series
2.	Extraction Steam Unit 1	2 in Series
3.	Extraction Steam Unit 2	2 in Series

Rapid depressurization occurs as a result of a line break at any point in the two (2) Auxiliary Steam headers. The mitigation scheme is such that any one of the four (4) pressure switches is designed to automatically close all of the Auxiliary Steam source isolation valves, except the Turbine Gland Steam Header, thereby preventing a turbine trip. In addition, the Auxiliary Steam System alarm and the High Energy Line Break (HELB) common trouble alarm are activated at the main control board.

A two (2) position switch ("Engage-Disengage") is provided at the Auxiliary Steam panel section of the main control board. This switch enables the operator to engage or disengage the mitigation circuitry, thus bypassing the isolation signal when the Auxiliary Steam System is being started up and auxiliary steam pressure is low. Placing the switch in the "Disengage" position activates the system alarm and also the HELB common trouble alarm, both located at the main control board. The alarm signal in this system is transmitted to both the Unit 1 and Unit 2 control rooms. The switch is normally placed in the "Engage" position.

7.6.12.2 Steam Generator Blowdown (SGB) System Line Break

One (1) flow indicating switch (FIS) is provided for each of the four (4) SGB lines. Each SGB line is provided with two isolation valves in series, between the SG and the postulated break. Extremely high flow measurement on three (3) FIS occurs as a result of a line break downstream or upstream of the FIS in any of the four (4) SGB lines. Any one of the four (4) FIS is designed to automatically close all of the SGB isolation valves. In addition, the SGB system alarm and the HELB common trouble alarm are activated at the main control board. These switches (FIS-5175, 5176, 5177 and 5178), shown on Figure 10.4-10 (Sh.1), are Non-Class 1E and Non-Seismic Category I.

See Section 10.4.8 for a description of the Steam Generator Blowdown System. The isolation valves, shown on Figure 10.3-1(Sh.1) are Nuclear Safety Related, Seismic Category I.

7.6.12.3 Chemical Volume and Control System (CVCS) Line Break

For a CVCS line break, mitigation is accomplished by detection and 10 minute operator action to isolate the system.

Rapid depressurization occurs as a result of a CVCS line break. Two pressure switches have been provided for the CVCS system to detect low system pressure. Each low pressure signal activates an alarm at the main control board and the operator manually isolates the system. The pressure switches are located remote from the environment resulting from a CVCS line break.

REFERENCES

1. The Institute of Electrical and Electronic Engineers, Inc., "IEEE Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations," IEEE Standard 308-1974.

2. The Institute of Electrical and Electronic Engineers, Inc., "IEEE Standard: Criteria for Protection Systems for Nuclear Power Generating Stations," IEEE Standard 279-1971.

3. The Institute of Electrical and Electronic Engineers, Inc., "IEEE Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection System," IEEE Standard 338-1971.

TABLE 7.6-1
LOSS OF ANY SINGLE INSTRUMENT

(Sheet 1 of 14)

SENSOR	NUMBER OF CHANNELS	FAILED CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECT	BOUNDING EVENT
Feedpump Discharge Pressure	1 per plant	_____	Feedwater Control	Lo	FW pump speed increases if in auto mode. (FW control valves close due to increased flow if in auto mode.)	If FW pump in manual - no event. If FW pump and FCV in auto – new steady state w/higher pump speed and decr. FCV lift. If FW pump in auto and FCV is manual - bounding event is Excessive FW Flow (FSAR 15.1.2)
				Hi	FW pump speed decreases if in auto mode. (FW control valves open due to decreased flow if in auto mode).	If FW pump in manual - no event. Other modes - result in a decreased FW flow over time, hence bounding event is loss of Normal FW Flow (FSAR 15.2.7).
Steam Header Pressure	1 per plant	_____	Feedwater Control Steam Dump (TAVG Mode)	Lo	FW pump speed decreases if in auto mode. (FW control valves open due to decreased flow if in auto mode).	If FW pump in manual - no event. Other modes - result in a decreased FW flow over time, hence bounding event is loss of Normal FW Flow (FSAR 15.2.7).

TABLE 7.6-1
LOSS OF ANY SINGLE INSTRUMENT

(Sheet 2 of 14)

SENSOR	NUMBER OF CHANNELS	FAILED CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECT	BOUNDING EVENT
				Hi	FW pump speed increases if in auto mode. (FW control valves close due to decreased flow if in auto mode).	If FW pump in manual - no event. If FW pump and FCV in auto – new steady state w/higher pump speed and decr. FCV lift. If FW pump in auto and FCV in manual - bounding event is Excessive FW Flow (FSAR 15.1.2).
Steam Header Pressure	1 per plant	_____	Feedwater Control Steam Dump (Pressure Mode)	Lo	FW pump speed decreases if in auto mode. (FW control valves open due to decreased flow if in auto mode).	If FW pump in manual - no event. Other modes - result in a decreased FW flow over time, hence bounding event is loss of Normal FW Flow (FSAR 15.2.7).

TABLE 7.6-1
LOSS OF ANY SINGLE INSTRUMENT

(Sheet 3 of 14)

SENSOR	NUMBER OF CHANNELS	FAILED CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECT	BOUNDING EVENT
				Hi	FW pump speed increases if in auto mode. (FW control valve close due to decreased flow if in auto mode).Dump valves open (Steam dump blocked on Lo-Lo TAVG (P-12).	Steam dump in pressure mode at hot standby or very low power only. Hence, dump valves will open for only a very short time till lo-lo TAVG (P-12) is reached. If FW pump speed is in manual or FW pump and FCV in auto, then this event is bounded by Excessive Increase in Secondary Steam Flow (FSAR 15.1.3). If FW pump in auto and FCV in manual, get increase in FW flow causing excessive cooling. Bounding event is Excessive FW Flow (FSAR 15.1.2).
Loop Steam Flow	2 per loop	1 selected for control	Feedwater Control	Lo	FW pump speed decreases if in auto mode. FW valves close if in auto mode.	If FW pump and FCV in manual – no event. Other modes result in decreased FW flow, bounding event is Loss of Normal FW Flow (FSAR 15.2.7).

TABLE 7.6-1
LOSS OF ANY SINGLE INSTRUMENT

(Sheet 4 of 14)

SENSOR	NUMBER OF CHANNELS	FAILED CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECT	BOUNDING EVENT
				Hi	FW pump speed increases if in auto mode. FW valves open if in auto mode.	If FW pump and FCV in manual – no event. Other modes - result in Increased FW flow, bounding event is Excessive FW Flow (FSAR 15.1.2).
Loop FW Flow	2 per loop	1 selected for Control	Feedwater Control	Lo	FW valve opens if in auto mode	If FCV in manual - no event. If FCV in auto, results is Excessive FW Flow (FSAR 15.1.2).
				Hi	FW valve closes if in auto mode	If FCV in manual - no event. If FCV is auto, result is decreased FW flow. Bounding event is Loss of Normal FW Flow (FSAR 15.2.7).
Narrow Range Level	4 per Steam Generator (two available for control)	1 selected for control I or II	Feedwater Control	Lo	FW valve opens if in auto mode	If FCV in manual - no event. If FCV in auto, result is Excessive FW Flow (FSAR 15.1.2).

TABLE 7.6-1
LOSS OF ANY SINGLE INSTRUMENT

(Sheet 5 of 14)

SENSOR	NUMBER OF CHANNELS	FAILED CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECT	BOUNDING EVENT
				Hi	FW valves closes if in auto mode	If FCV in manual - no event. If FCV is auto, result is decreased FW flow. Bounding event is Loss of Normal FW Flow (FSAR 15.2.7).
Pressurizer Level (Control)	3 per unit	I or III	Prz. Level Control	Lo	Charging flow increases. Heaters turn off (except for local control). Letdown isolated (VCT empties, charging pumps take suction from RWST.)	Bounding event is Increased Reactor Coolant Inventory (FSAR 15.5.2).
				Hi	Charging flow decreases Backup heaters on (Later, letdown isolation from interlock channel, heaters blocked from interlock channel.)	While heaters are on, no net depressurization of RCS. After heaters are blocked, decreased charging flow acts to depressurize RCS. Depressurization event is therefore bounded by Inadvertent Opening of a Pressurizer Safety or Relief Valve (FSAR 15.6.1)

TABLE 7.6-1
LOSS OF ANY SINGLE INSTRUMENT

(Sheet 6 of 14)

SENSOR	NUMBER OF CHANNELS	FAILED CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECT	BOUNDING EVENT
Pressurizer Level (Interlock)	3 per unit	II or II	Prz. Level Control	Lo	Letdown isolated. Prz. Heaters blocked (except for local control). (Charging flow reduced to maintain level).	Steady-state reached at slightly high level. No event.
				Hi	No control action, get Hi level annunciation.	Not applicable
Pressurizer Pressure	4 per unit	I	Prz. Pressure Control (Pos. 1 or 2)[(a)]	Lo	Turn on Backup Heaters. PORV 455A blocked from opening. PORV 456 opens if required, closes when pressure falls below dead band. Spray remains off.	Heaters being on causes increase in Prz. pressure to PORV 456 actuation. No event.
				Hi	PORV 455A opens, closes when pressure falls below deadband. Spray turned on.	Result is bounded by Inadvertent Opening of a Prz. Safety or Relief Valve (FSAR 15.6.1).
			(Pos. 3)[(a)]		Channel not connected	Not applicable

TABLE 7.6-1
LOSS OF ANY SINGLE INSTRUMENT

(Sheet 7 of 14)

SENSOR	NUMBER OF CHANNELS	FAILED CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECT	BOUNDING EVENT
Pressurizer Pressure	4 per unit	II	Prz. Pressure Control (Pos. 2 or 3)[(a)]	Lo	No control action. PORV 456 blocked from opening. PORV 455A Opens if required, closes when pressure falls below deadband.	Not applicable
				Hi	PORV 456A Opens, closes when pressure falls below deadband Spray turned on.	Result is bounded by Inadvertent Opening of a Prz. Safety or Relief Valve (FSAR 15.6.1)
			(Pos. 1)[(a)]		Channel not connected	Not applicable
Pressurizer Pressure	4 per unit	III	Prz. Pressure Control (Pos. 3)[(a)]	Lo	Turn on Backup Heaters. PORV 455A and 456 blocked from opening Spray remains off.	Heaters being on causes increase in Prz. pressure, possibly to safety valve actuation and reactor trip. Bounding event is Loss of Normal FW Flow (FSAR 15.1.2).
				Hi	PORV 455A Opens, closed on low pressure interlock. Spray turned on. PORV 456 unblocked.	Result is bounded by Inadvertent Opening of a Prz. Safety or Relief Valve (FSAR 15.6.1)

TABLE 7.6-1
LOSS OF ANY SINGLE INSTRUMENT

(Sheet 8 of 14)

SENSOR	NUMBER OF CHANNELS	FAILED CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECT	BOUNDING EVENT
			(Pos. 1 or 2)[a]	Lo	Block PORV 456 from opening; no control action.	Not applicable
				Hi	Unblock PORV 456; no control action.	Not applicable
Pressurizer Pressure	4 per unit	IV	Prz. Pressure Control (Pos. 1)[a]	Lo	Block PORV 456 & 455A from opening; no control action.	Not applicable
				Hi	PORV 455A unblocked. PORV 456 opens, closes when pressure falls below deadband.	Result is bounded by Inadvertent Opening of a Prz. Safety or Relief Valve (FSAR 15.6.1).
			(Pos. 2 or 3)[a]	Lo	Block PORV 455A from opening; no control action	Not applicable
				Hi	Unblock PORV 455A; no control action	Not applicable

TABLE 7.6-1
LOSS OF ANY SINGLE INSTRUMENT

(Sheet 9 of 14)

SENSOR	NUMBER OF CHANNELS	FAILED CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECT	BOUNDING EVENT
TAVG	one per loop	Any TAVG	Steam Dump Reactor Control Prz. Level Control	Lo	• Stop turbine loading, defeat remote dispatching (C-16 Annunciation occurs). • Outward rod motion (non-conservative direction), reactor trip on N16 over temperature trip. If C2, C3, C4 block rods so power does not significantly increase, reactor trip on High Flux trip, whether or not a high flux reactor trip occurs depends upon initial bank D position; the magnitude of the negative moderator temperature coefficient (MTC), magnitude of the doppler-only power coefficient (DOPC).	Bounded by analysis of control rod withdrawal events in FSAR Section 15.4.

TABLE 7.6-1
LOSS OF ANY SINGLE INSTRUMENT

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SENSOR	NUMBER OF CHANNELS	FAILED CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECT	BOUNDING EVENT
					• Charging flow decreases to minimum causing Pressurizer level decrease to a minimum level.	
		Auct. Lo	Turbine Loading Dispatching	Hi	• Rods in (safe direction) at max speec results in lo pressure reactor trip or over temperature N16 reactor trip. • Charging flow increases until full power Prz, level is reached (if at reduced power). If reactor trips steam dump enabled and dump valves open until steam dump stops when Lo-lo TAVG is reached.	No event unless reactor trips, then dump valves open and bounding event is Excessive Increase in Secondary Steam Flow (FSAR 15.1.3)
Steamline Pressure	1 per loop for control different from those used for protection	Control Channel	Steam Dump	Lo	No control action	Not applicable

TABLE 7.6-1
LOSS OF ANY SINGLE INSTRUMENT

(Sheet 11 of 14)

SENSOR	NUMBER OF CHANNELS	FAILED CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECT	BOUNDING EVENT
				Hi	S. GEN. relief valve opens.	Bounding event is Inadvertent Opening of a Steam Generator Relief or Safety Valve (FSAR 15.1.4)
Intermediate Range Flux	2 per plant	I or II	Reactor Control	Lo	No control action.	Not applicable
				Hi	Reactor trips if below P-10 interlock.	Not applicable
Turbine Impulse Chamber Pressure (Control)	2 per turbine	I (Pos. 1)[(a)] or II (Pos. 2)[(a)]	Steam Dump (TAVG Mode) Reactor Control FW Control	Lo	Rods in (safe direction), auto rods withdrawal blocked (C-5). (If reactor trip occurs, steam dump unblocked and dump valves modulate until no load TAVG is reached). No effect on FW control since have constant S.G. level program.	Not applicable

TABLE 7.6-1
LOSS OF ANY SINGLE INSTRUMENT

(Sheet 12 of 14)

SENSOR	NUMBER OF CHANNELS	FAILED CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECT	BOUNDING EVENT
				Hi	Rods out until blocked by Hi flux, overpower, or overtemperature, rod stop, or until programmed TREF limit is reached. (If reactor trip occurs, steam dump unblocked and dump valves open until no load TAVG is reached). No effect of FW control since have constant S.G. level program.	Result is bounded by Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (FSAR 15.4.2)
Turbine Impulse Chamber Pressure (Control)	2 per turbine	I (Pos. 1)[a] or II (Pos. 2)[a]	Steam Dump (Pressure Mode) Reactor Control FW Control	Lo	Rods in, (safe direction) auto rod withdrawal blocked (C-5). No effect on FW control since have constant S.G. level program.	Not applicable
				Hi	Rods out until blocked by Hi flux, overpower, or overtemperature rod stop. Dump valves open to keep steam header pressure at or below setpoint. No effect on FW control.	Result is bounded by Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (FSAR 15.4.2)

TABLE 7.6-1
LOSS OF ANY SINGLE INSTRUMENT

(Sheet 13 of 14)

SENSOR	NUMBER OF CHANNELS	FAILED CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECT	BOUNDING EVENT
Turbine Impulse Chamber Pressure (Interlock)	2 per turbine	II	Steam Dump (TAVG Mode)	Lo	Unblock steam dump	Not applicable
				Hi	Block steam dump.	Not applicable
Turbine Impulse Chamber Pressure (Interlock)	2 per turbine	I II	Steam Dump (Pressure Mode)	Lo or Hi	No control Action.	Not applicable
Power Range Flux	4 per unit	Any	Reactor Control FW Control	Lo	No control action (auctioneered Hi)	Not applicable
				Hi	Auto and manual rod withdrawal blocked (C-2), rods in (in safe direction). No effect on FW bypass valve due to nuclear feedforward gain set to zero. (If reactor trip occurs, dump valves open until no load TAVG is reached).	No event.

TABLE 7.6-1
LOSS OF ANY SINGLE INSTRUMENT

(Sheet 14 of 14)

SENSOR	NUMBER OF CHANNELS	FAILED CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECT	BOUNDING EVENT
Condenser Available	2 per condenser	Any	Steam Dump	Lo	No control action - steam dump unblocked, condenser available.	Not applicable
				Hi	No control action - steam dump blocked, condenser unavailable.	Not applicable
Steam Flow Pressure Compensator	2 per loop	Control Channel	Steam Flow	Lo	Identical to Loop Steam Flow channel failing low. See analysis above.	See above
				Hi	Identical to Loop Steam Flow channel failing high. See analysis above.	See above

a) Signals for pressurizer and turbine impulse chamber pressure can be obtained from different channels. Selection of desired channels is done by manual switches in the control room. Resulting accident due to failed instrument is dependent on switch positions.

TABLE 7.6-2
LOSS OF POWER TO PROTECTION SET I

CONTROL SYSTEMS AFFECTED	SIGNALS AFFECTED	FAILURE DIRECTION	ITEMIZED EFFECTS	BOUNDING EVENT
Steam Dump	Turbine Pressure (Control or Interlock)	Low	Steam dump demanded but blocked from interlock. If reactor trips, steam dump valves modulate.	
Reactor Control	Power Range Flux (Control)	Low	If Turbine pressure on control channel, rods in (safe direction), power decreases and stop turbine loading/defeat remote dispatching. Otherwise, no control action.	Bounding event is Excessive FW Flow (FSAR 15.1.2). Hi-Hi SG level closes FW control and isolation valves, trips FW turbine, and main turbine. Increased charging flow and pressurizer transients have little effect in comparison.
	Turbine Pressure (Control)	Low		
	TAVG (Loop 1)	Low		
FW Control	Narrow Range Level SG No. 1 and 4	Low	If affected level signal used for control, FCV opens in loops 1 and 4. If affected steam flow pressure compensation used, control logic would cause FW flow in loops 2 and 3 to decrease with subsequent return to normal condition. Steam pressure compensation signal effects in loops 1 and 4 negligible in comparison to level signal effects.	
	Steam Flow Pressure Compensation (All Loops)	Low		
Pressurizer	Pzr. Level (Control and Interlock)	Low	Letdown isolated, heaters blocked if affected level signal used for control. Charging flow increases.	
Pressurizer Pressure	Pzr. Pressure	Low	PORV 455A stays closed. (PORV 456 available if required.) If affected pressure signal used for control spray off.	

TABLE 7.6-3
LOSS OF POWER TO PROTECTION SET II

CONTROL SYSTEMS AFFECTED	SIGNALS AFFECTED	FAILURE DIRECTION	ITEMIZED EFFECTS	BOUNDING EVENT
Steam Dump	Turbine Pressure (Control or Interlock)	Low	No control action, and steam dump blocked. If reactor trips main steam relief valves available.	Bounding event is Excessive FW Flow (FSAR 15.1.2). Hi-Hi SG level closes FW control and isolation valves, trips FW turbine, and main turbine.
Reactor Control	Power Range Flux (Control)	Low	If Turbine pressure on control channel, rods in (safe direction), power decreases and stop turbine loading/defeat remote dispatching. Otherwise, no control action.	
	Turbine Pressure (Control)	Low		
	TAVG (Loop 1)	Low		
FW Control	Narrow Range Level SG No. 2and 3	Low	If affected level signal used for control, FCV opens in loops 2 and 3 If affected steam flow pressure compensation used, control logic would cause FW flow in loops 1 and 4 to decrease with subsequent return to normal condition. Steam pressure compensation signal effects in loops 2 and 3 negligible in comparison to level signal effects.	
	Steam Flow Pressure Compensation (All Loops)	Low		
Pressurizer	Pzr. Level (Interlock)	Low	If affected level signal used for interlock, heaters off, letdown isolated, charging flow unaffected. Otherwise, channel not connected, no control action.	
Pressurizer Pressure	Pzr. Pressure	Low	PORV 456 stays closed. (PORV 455A available if required.) Otherwise, channel not connected, no control action.	

TABLE 7.6-4
LOSS OF POWER TO PROTECTION SET III

CONTROL SYSTEMS AFFECTED	SIGNALS AFFECTED	FAILURE DIRECTION	ITEMIZED EFFECTS	BOUNDING EVENT
Steam Dump	None	---	No signals affected, no control action	With htrs on, and spray off, high pressurizer pressure trip is actuated. Event is bounded by loss of normal feedwater (FSAR 15.2.7). Bounding events due to charging flow increase or letdown isolated are slowly developing; alarms in the control room would allow the operator ample time to restore power.
Reactor Control	Power Range Flux (Control)	Low	Stop turbine loading, defeat remote dispatching	
	TAVG (Loop 3)	Low		
FW Control	None	---	No signals affected, no control action	
Pressurizer Level	Pzr. Level (Control or Interlock)	Low	If affected level signal used for control, charging flow increases, letdown isolated, heaters blocked. If used for interlock, heaters blocked and letdown isolated. Otherwise, channel not connected, no control action.	
Pressurizer Pressure	Pzr. Pressure (Interlock and Control)	Low	PORV 455A and 456 stay closed. If affected pressure signal used for control, backup heaters on (if allowed by level signal, see above) and spray off. Otherwise, spray available if required.	

TABLE 7.6-5
LOSS OF POWER TO PROTECTION SET IV

CONTROL SYSTEMS AFFECTED	SIGNALS AFFECTED	FAILURE DIRECTION	ITEMIZED EFFECTS	BOUNDING EVENT
Steam Dump	None	---	No signals affected, no control action	
Reactor Control	Power Range Flux (Control)	Low	Stop turbine loading, defeat remote dispatching	
	TAVG (Loop 4)	Low		
FW Control	None	---	No signals affected, no control action	No event is initiated due to loss of power, therefore bounding event is not applicable.
Pressurizer Level	None	---	No signals affected, no control action	
Pressurizer Pressure	Pzr. Pressure (Control and Interlock)	Low	PORV 455A and 456 stay closed.	

TABLE 7.6-6
LOSS OF COMMON INSTRUMENT LINES (ASSUMED BREAK IN LINE)

SENSORS	FAILED CHANNELS	SYSTEM	FAILURE DIRECTION	EFFECT	BOUNDING EVENT
Loop Steam Flow and Narrow Range Level	II	Feedwater Control	Lo Hi	FW valve closes in affected S.G., pump speed decreases	Bounding event is Loss of Normal FW Flow (FSAR 15.1.2)
Pressurizer Level (Control) and Pressurizer Pressure	I (Level and Pressure)	Pzr. Level Control Pzr. Pressure Control	Hi Lo	PORV 455A stays closed. Spray unavailable. Charging flow decreases (Control). Backup heaters on (Control). (On low level, letdown isolated and heaters blocked from interlock channel).	Bounding event is inadvertent opening of a Prz. Safety or Relief Valve (FSAR 15.6.1)
Pressurizer Level (Interlock) and Pressurizer Pressure	III (Level and Pressure)	Pzr. Level Control Pzr. Pressure Control	Hi Lo	Scenario dependant upon selector switch position, bracketing effects are: PORV 455A and 456 stay closed, spray unavailable, backup htrs on, charging flow decrease, on low level letdown isolated, htrs blocked.	Bounding event is Loss of Normal FW Flow (FSAR 15.1.2)
Pressurizer Level (control or Interlock) and Pressurizer Pressure	II (Level) II and IV (Pressure)	Pzr. Pressure Control	Hi	PORV 455A and 456 stay closed. Spray, charging flow, letdown isolation, and htr controls unaffected.	No event

7.7 CONTROL SYSTEMS NOT REQUIRED FOR SAFETY

The general design objectives of the plant control systems are:

1. To establish and maintain power equilibrium between primary and secondary system during steady state unit operation.

2. To constrain operational transients so as to preclude unit trip and re-establish steady state unit operation.

3. To provide the reactor operator with monitoring instrumentation that indicates all required input and output control parameters of the systems and provides the operator the capability of assuming manual control of the system.

7.7.1 DESCRIPTION

The plant control systems described in this section perform the following functions:

1. Reactor Control System

    a. Enables the nuclear plant to accept a step load increase or decrease of 10 percent and a ramp increase or decrease of 5 percent per minute within the load range of 15 percent to 100 percent without reactor trip, steam dump, or pressurizer relief actuation, subject to possible xenon limitations.

    b. Maintains reactor coolant average temperature within prescribed limits by creating the bank demand signals for moving groups of full length rod cluster control assemblies during normal operation and operational transients. The reactor coolant average temperature control also supplies a signal to pressurizer water level control, and steam dump control.

2. Rod Control System

    a. Provides for reactor power modulation by manual or automatic control of full length control rod banks in a pre-selected sequence and for manual operation of individual banks.

    b. Systems for monitoring and indicating

        1. Provide alarms to alert the operator if the required core reactivity shutdown margin is not available due to excessive control rod insertion.

        2. Display control rod position.

        3. Provide alarms to alert the operator in the event of control rod deviation exceeding a preset limit.

3. Plant Control System interlocks

   a. Prevent further withdrawal of the control banks when signal limits are approached that predict the approach of a departure from nucleate boiling ratio (DNBR) limit or kilowatt per feet (kW/ft) limit.

   b. Inhibit automatic turbine load change as required by the Nuclear Steam Supply System (NSSS).

4. Pressurizer pressure control

   a. Maintains or restores the pressurizer pressure to the design pressure +30 pounds per square inch (psi) (which is well within reactor trip and relief and safety valve actuation setpoint limits) following normal operational transients that induce pressure changes by control (manual or automatic) of heaters and spray in the pressurizer.

      Provides steam relief by controlling the power relief valves.

5. Pressurizer water level control

   a. Establishes, maintains, and restores pressurizer water level within specified limits as a function of the average coolant temperature. Changes in level are caused by coolant density changes induced by loading, operational, and unloading transients. Level changes are produced by means of charging flow control (manual or automatic) as well as by manual selection of letdown orifices. Maintaining coolant level in the pressurizer within prescribed limits by actuating the charging and letdown system thus provides control of the reactor coolant water inventory.

6. Steam generator water level control

   a. Establishes and maintains the steam generator water level to within pre-determined physical limits during normal operating transients.

   b. Restores the steam generator water level to within predetermined limits at unit trip conditions. Regulates the feedwater flow rate such that under operational transients the heat sink for the Reactor Coolant System (RCS) is maintained.

7. Steam dump control

   a. Permits the nuclear plant to accept a sudden loss of load without incurring reactor trip. Steam is dumped to the condenser and/or the atmosphere as necessary to accommodate excess power generation in the reactor during turbine load reduction transients.

   b. Ensures that stored energy and residual heat are removed following a reactor trip to bring the plant to equilibrium no-load conditions without actuation of the steam generator safety valves.

c. Maintains the plant at no-load conditions and permits a manually controlled cooldown of the plant.

8. Incore instrumentation

Provides information on the neutron flux distribution and on the core outlet temperatures at selected core locations.

7.7.1.1 Reactor Control System

The Reactor Control System enables the nuclear plant to follow load changes automatically including the acceptance of step load increase or decreases of 10 percent and ramp increases or decreases of 5 percent per minute within the load range of 15 percent to 100 percent without reactor trip, steam dump, or pressure relief (subject to possible xenon limitations). The system is also capable of restoring coolant average temperature to within the programmed temperature deadband following a change in load. Manual control rod operation may be performed at any time.

The Reactor Control System controls the reactor coolant average temperature by regulation of control rod bank position. The reactor coolant loop average temperatures are determined from N-16 power and cold leg measurements in each reactor coolant loop. There is an average coolant temperature (T_{avg}) computed for each loop, as shown on Figure 7.7-18:

$$T_{avg} = T_{cold} + K \times Q_{N-16}$$

The error between the programmed reference temperature (based on turbine first stage pressure) and the average of the T_{avg} measured temperatures (which is processed through a lead-lag compensation unit) from each of the reactor coolant loops constitutes the primary control signal as shown in general on Figure 7.7-1 and in more detail on the functional diagrams shown in Figure 7.2-1, Sheet 9. The system is capable of restoring coolant average temperature to the programmed value following a change in load. The programmed coolant temperature increases linearly with turbine load from zero power to the full power condition. The T_{avg} also supplies a signal to pressurizer level control and steam dump control.

The temperature and N-16 channels needed to derive the temperature input signals for the Reactor Control System are fed from protection channels via isolation amplifiers.

An additional control input signal is derived from the reactor power versus turbine load mismatch signal. This additional control input signal improves system performance by enhancing response and reducing transient peaks.

The core axial power distribution is controlled during load follow maneuvers by changing (a manual operator action) the boron concentration in the RCS. The control board displays (see Section 7.7.1.3.1) indicate the need for an adjustment in the axial power distribution. Adding boron to the reactor coolant will reduce T_{avg} and cause the rods (through the Rod Control System) to move toward the top of the core. This action will reduce power peaks in the bottom of the core. Likewise, removing boron from the reactor coolant will move the rods further into the core to control power peaks in the top of the core.

7.7.1.2 Rod Control System

The full length rod control system receives rod speed and direction signals from the T_{avg} control system. The rod speed demand signal varies over the corresponding range of 5 to 45 inches per minute (8 to 72 steps/minute) depending on the magnitude of the input signal. Manual control is provided to move a control bank in or out at a prescribed fixed speed.

When the turbine load reaches approximately 15 percent of rated load, the operator may select the “AUTOMATIC” mode, and rod motion is then controlled by the reactor control systems. A permissive interlock C-5 (see Table 7.7-1) derived from measurements of turbine first stage pressure prevents automatic control when the turbine load is below 15 percent. In the “AUTOMATIC” mode, the rods are again withdrawn (or inserted) in a pre-determined programmed sequence by the automatic programming with the control interlocks (see Table 7.7-1).

The shutdown banks are always in the fully withdrawn position during normal operation, and are moved to this position at a constant speed by manual control prior to criticality. A reactor trip signal causes them to fall by gravity into the core. There are five shutdown banks.

The control banks are the only rods that can be manipulated under automatic control. Each control bank is divided into two groups to obtain smaller incremental reactivity changes per step. All rod control cluster assemblies in a group are electrically paralleled to move simultaneously. There is individual position indication for each rod cluster control assembly.

Power to rod drive mechanisms is supplied by two motor generator sets operating from two separate 480 volt, three phase buses. Each generator is the synchronous type and is driven by a 200 horsepower (hp) induction motor. The alternating current (AC) power is distributed to the rod control power cabinets through the two series connected reactor trip breakers.

The variable speed rod drive programmer affords the ability to insert small amounts of reactivity at low speed to accomplish fine control of reactor coolant average temperature about a small temperature deadband, as well as furnishing control at high speed. A summary of the rod cluster control assembly sequencing characteristics is given below.

1. Two groups within the same bank are stepped such that the relative position of the groups will not differ by more than one step.

2. The control banks are programmed such that withdrawal of the banks is sequenced in the following order: control bank A, control bank B, control bank C, and control bank D. The programmed insertion sequence is the opposite of the withdrawal sequence; i.e., the last control bank withdrawn (bank D) is the first control bank inserted.

3. The control bank withdrawals are programmed such that when the first bank reaches a preset position, the second bank begins to move out simultaneously with the first bank which continues to move toward its fully withdrawn position. When the second bank reaches a preset position, the third bank begins to move out, and so on. This withdrawal sequence continues until the unit reaches the desired power level. The control bank insertion sequence is the opposite.

4. Overlap between successive control banks is adjustable between 0 to 50 percent (0 and 115 steps), with an accuracy of ±1 step.

5. Rod speeds for either the shutdown banks or manual operation of the control banks are capable of being controlled between a minimum of 6 steps per minute and a maximum of 68 steps per minute.

7.7.1.3 Plant Control Signals for Monitoring and Indicating

7.7.1.3.1 Monitoring Functions Provided by the Nuclear Instrumentation System (NIS)

The power range channels are important because of their use in monitoring power distribution in the core within specified safe limits. They are used to measure power level, axial flux imbalance, and radial flux imbalance. These channels are capable of recording overpower excursions up to 200 percent of full power. Suitable alarms are derived from these signals as described below.

Basic power range signals are:

1. Total current from a power range detector (four such signals from a power range detector assembly, i.e., one detector assembly per core quadrant); each detector set consists of 4 power range detectors.

2. Current from the sum of the upper two detectors of each power range detector assembly (four such signals).

3. Current from the sum of the lower two detectors, of each power range detector assembly (four such signals).

Derived from these basic signals are the following (including standard signal processing for calibration).

4. Indicated nuclear power (four such).

5. Indicated axial flux difference ($\Delta\phi$), derived from the sum of the upper two detectors in an assembly minus the sum of the lower two detectors in an assembly (four such).

Alarm functions derived are as follows:

6. Deviation (maximum minus minimum of four) in indicated nuclear power.

7. Upper radial tilt (maximum to average of four) on average of the upper two detector sets' currents.

8. Lower radial tilt (maximum to average of four) on average of the lower two detector sets' currents.

Provision is made to continuously record, on strip charts on the control board, the 8 groups of the ion chamber signals, i.e., average of the upper and average of the lower currents for each detector assembly. Nuclear power and axial unbalance is selectable for recording as well. Indicators are provided on the control board for nuclear power and for axial flux difference.

The axial flux difference deviation alarms are derived from the plant process computer which determines the 1 minute averages of the excore detector outputs to monitor $\Delta\phi$ in the reactor core and alerts the operator where $\Delta\phi$ alarm conditions exist. When power level is 50 percent or greater, an alarm message is output immediately upon determining a delta flux exceeding the Technical Specifications (this alarm requires 2 of the 4 AFD channels to exceed the power dependent limits). The signals from the four section excore detectors are summed and calibrated to a power measurement made using a secondary system calorimetric. The signals from the upper two sections and lower two sections are combined to give an upper flux and lower flux signal as shown in Figure 7.1-2. These upper and lower signals must be calibrated to agree with axial offset measurements derived from flux maps made using the movable incore system. The NIS provides both slope and zero-offset adjustments to achieve this calibration.

Additional background information on the Nuclear Instrumentation System can be found in Reference [1].

7.7.1.3.2 Rod Position Monitoring of Full Length Rods

Two separate systems are provided to display control rod position as described below:

1. Digital Rod Position Indication System

   The Digital Rod Position Indication System (DRPIS) measures the actual position of each full length rod using a detector which consists of discrete coils mounted concentrically with the rod drive pressure housing. The coils are located axially along the pressure housing and magnetically sense the entry and presence of the rod drive shaft through its centerline. For each detector, the coils are interlaced into two data channels, and are connected to the Containment electronics (Data A and B) by separate multi-conductor cables. By employing two separate channels of information, the DRPIS can continue to function (at reduced accuracy) when one channel fails. Multiplexing is then used to transmit the digital position signals from the Containment electronics to the control board display unit.

   The control board display unit contains a column of light- emitting-diodes (LED) for each rod. At any given time, the one LED illuminated in each column shows the position for that particular rod. Since shutdown rods are always fully withdrawn with the plant at power, their position is displayed in 6 step increments with an accuracy of ±4 steps only from rod bottom to 18 steps and from 210 steps to 228 steps. All intermediate positions of the rod are represented by a single “transition” LED. Each rod of the control banks has its position displayed in 6 step increments with an accuracy of ±4 steps throughout its range of travel.

   Included in the system is a rod at bottom signal for each rod that operates an alarm. Also a Control Room annunciator is actuated for any misaligned rod at bottom.

2. Demand Position System

   The Demand Position System counts pulses generated in the rod drive control system to provide a digital readout of the demanded bank position.

The demand position and digital rod position indication systems are separate systems, but safety criteria were not involved in the separation, which was a result only of operational requirements. Operating procedures require the reactor operator to compare the demand and indicated (actual) readings from the DRPIS so as to verify operation of the Rod Control System.

7.7.1.3.3 Control Bank Rod Insertion Monitoring

When the reactor is critical, the normal indication of reactivity status in the core is the position of the control bank in relation to reactor power and coolant average temperature. These parameters are used to calculate insertion limits for the control banks. Two alarms are provided for each control bank.

1. The “low” alarm alerts the operator of an approach to the rod insertion limits requiring boron addition by following normal procedures with the Chemical and Volume Control System.

2. The “low-low” alarm alerts the operator to take action to ensure shutdown margin is within limits or restored within limits per Technical Specification.

The purpose of the control bank rod insertion monitor is to give warning to the operator of excessive rod insertion. The insertion limit maintains sufficient core reactivity shutdown margin following reactor trip and provides a limit on the maximum inserted rod worth in the unlikely event of a hypothetical rod ejection, and limits rod insertion such that acceptable nuclear peaking factors are maintained. Since the amount of shutdown reactivity required for the design shutdown margin following a reactor trip increases with increasing power, the allowable rod insertion limits must be decreased (the rods must be withdrawn further) with increasing power. The rod insertion monitor uses the N-16 power parameters for each control rod bank as follows:

$$Z_{LL} = A(\text{N-16 power})_{auct} + C$$

where

Z_{LL}	=	maximum permissible insertion limit for affected control bank
$(\text{N-16})_{auct}$	=	highest N-16 of all loops
A,C	=	constant chosen to maintain $Z_{LL} \geq$ actual limit based on physics calculations

The control rod bank demand position (Z) is compared to Z_{LL} as follows:

1. If $Z - Z_{LL} \leq D$ a low alarm is actuated.

2. If $Z - Z_{LL} \leq E$ a low-low alarm is actuated.

Since the highest value of N-16 power is chosen by auctioneering, a conservatively high representation of power is used in the insertion limit calculation.

Actuation of the low alarm alerts the operator of an approach to a reduced shutdown reactivity situation. Administrative procedures require the operator to add boron through the Chemical and Volume Control System. Actuation of the low-low alarm requires the operator to verify shutdown margin within limits or to take actions to restore the shutdown margin in accordance with Technical Specification. The value for "D" is chosen such that the low alarm would normally be actuated before the insertion limit is reached. This allows the operator to follow normal boration procedures. Figure 7.7-2 shows a block diagram representation of the control rod bank insertion monitor. The monitor is shown in more detail on the functional diagrams shown in Figure 7.2-1, Sheet 9. In addition to the rod insertion monitor for the control banks, the plant computer, which monitors individual rod positions, provides an alarm that is associated with the rod deviation alarm discussed in Section 7.7.1.3.4 is provided to warn the operator if any shutdown rod cluster control assembly leaves the fully withdrawn position.

Rod insertion limits are established by:

1. Establishing the allowed rod reactivity insertion at full power consistent with the purposes given above.

2. Establishing the differential reactivity worth of the control rods when moved in normal sequence.

3. Establishing the change in reactivity with power level by relating power level to rod position.

4. Linearizing the resultant limit curve. All key nuclear parameters in this procedure are measured as part of the initial and periodic physics testing program.

Any unexpected change in the position of the control bank under automatic control, or a change in coolant temperature under manual control, provides a direct and immediate indication of a change in the reactivity status of the reactor. In addition, samples are taken periodically of coolant boron concentration. Variations in concentration during core life provide an additional check on the reactivity status of the reactor, including core depletion.

7.7.1.3.4 Rod Deviation Alarm

A rod deviation function is performed as part of the DRPIS where an alarm is generated if a preset limit is exceeded as a result of a comparison of any control rod against the other rods in a bank. The deviation alarm of a shutdown rod is based on a preset insertion limit being exceeded.

The demanded and measured rod position signals are also monitored by the plant computer which provides a visual printout and an audible alarm whenever an individual rod position signal deviates from the other rods in the bank by a preset limit. The alarm can be set with appropriate allowance for instrument error and within sufficiently narrow limits to preclude exceeding core design hot channel factors.

Figure 7.7-3 is a block diagram of the rod deviation comparator and alarm system implemented by the plant computer. Additionally, the DRPIS contains rod deviation circuitry that detects and alarms the following conditions:

1. When any two rods within the same control bank are misaligned by a preset distance (≥ 12 steps), and

2. When any shutdown rod is below the full-out position by a preset distance (18 steps).

7.7.1.3.5 Rod Bottom Alarm

A rod bottom signal for the full length rods in the digital rod position system is used to operate a control relay, which generates the “ANY ROD AT BOTTOM” AND/OR “≥ 2 ROD AT BOTTOM” alarm.

7.7.1.4 Plant Control System Interlocks

The listing of the plant control system interlocks, along with the description of their derivations and functions, is presented in Table 7.7-1. It is noted that the designation numbers for these interlocks are preceded by “C”. The development of these logic functions is shown in the functional diagrams (Figure 7.2-1, Sheets 9 through 16).

7.7.1.4.1 Rod Stops

Rod stops are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal initiated by either a control system malfunction or operator violation of administrative procedures.

Rod stops are the C-1, C-2, C-3, C-4, C-5, and C-11 control interlocks identified in Table 7.7-1. The C-3 rod stop derived from Overtemperature N-16 and the C-4 rod stop, derived from Overpower N-16 are also used for turbine runback, which is discussed below.

7.7.1.4.2 Automatic Turbine Load Runback

Automatic turbine load runback is initiated by an approach to an overpower or overtemperature condition. This will prevent high power operation that might lead to an undesirable condition, which, if reached, will be protected by reactor trip.

Turbine load reference reduction is initiated by either an Overtemperature or Overpower N-16 signal. Two out of four coincidence logic is used.

A rod stop and turbine runback are initiated when:

$$Q_{N\text{-}16} > Q_{rod\ stop}$$

for both the overtemperature and the overpower condition.

For either condition in general:

$$Q_{rod\ stop} = Q_{setpoint} - C$$

where

C = a Constant

where $Q_{setpoint}$ refers to the Overtemperature N-16 reactor trip value and the Overpower N-16 reactor trip value for the two conditions.

The turbine runback is continued until N-16 power is equal to or less than $Q_{rod\ stop}$.

This function serves to maintain an essentially constant margin to trip.

In addition to the fast turbine runback initiated by Overtemperature or Overpower N-16 parameters, an automatic turbine load runback is initiated by the following condensate/feedwater system malfunctions:

1. Main feedwater pump trip.

2. Condensate pump trip.

3. Heater drain pump trip.

The above runbacks are within the capability of automatic reactor load following. However, a condensate pump trip may result in a plant trip due to loss of feedwater or low levels in the steam generators.

7.7.1.4.3 Turbine Loading Stop

An interlock (C-16) is provided to limit turbine loading during a rapid return to power transient when a reduction in reactor coolant temperature is used to increase reactor power (through the negative moderator coefficient). This interlock limits the drop in coolant temperature to exceed cooldown accident limits and preserves satisfactory steam generator operating conditions. Subsequent automatic turbine loading can begin after the interlock has been cleared by an increase in coolant temperature which is accomplished by reducing the boron concentration in the coolant.

7.7.1.5 Pressurizer Pressure Control

The RCS pressure is controlled by using either the heaters (in the water region) or the spray (in the steam region) of the pressurizer plus steam relief for large transients. The electrical immersion heaters are located near the bottom of the pressurizer. A portion of the heater group is proportionally controlled to correct small pressure variations. These variations are due to heat losses, including heat losses due to a small continuous spray. The remaining (back-up) heaters are turned on when the pressurizer pressure controlled signal demands approximately 100 percent proportional heater power.

The spray nozzles are located on the top of the pressurizer. Spray is initiated when the pressure controller spray demand signal is above a given setpoint. The spray rate increases proportionally with increasing spray demand signal until it reaches a maximum value.

Steam condensed by the spray reduces the pressurizer pressure. A small continuous spray is normally maintained to reduce thermal stresses and thermal shock and to help maintain uniform water chemistry and temperature in the pressurizer.

Power relief valves limit system pressure for large positive pressure transients. In the event of a large load reduction, not exceeding the design plant load rejection capability, the pressurizer power operated relief valves might be actuated for the most adverse conditions, e.g., Beginning of Life conditions. The relief capacity of the power operated relief valves is sized large enough to limit the system pressure to prevent actuation of high pressure reactor trip for the above condition.

A block diagram of the Pressurizer Pressure Control System is shown on Figure 7.7-4.

7.7.1.6 Pressurizer Water Level Control

The pressurizer operates by maintaining a steam cushion over the reactor coolant. As the density of the reactor coolant adjusts to the various temperatures, the steam water interface moves to absorb the variations with relatively small pressure disturbances.

The water inventory in the RCS is maintained by the Chemical and Volume Control System. During normal plant operation, the charging flow varies to produce the flow demanded by the pressurizer water level controller. The pressurizer water level is programmed as a function of coolant average temperature, with the average temperature being used. The pressurizer water level decreases as the load is reduced from full load. This is a result of coolant contraction following programmed coolant temperature reduction from full power to low power. The programmed level is designed to match as nearly as possible the level changes resulting from the coolant temperature changes.

To control pressurizer water level during startup and shutdown operations, the charging flow is manually regulated from the main Control Room.

A block diagram of the Pressurizer Water Level Control System is shown on Figure 7.7-5.

7.7.1.7 Steam Generator Water Level Control

Each steam generator is equipped with a three element feedwater flow controller which maintains a programmed water level which is a function of turbine load. The three element feedwater controller regulates the feedwater valve by continuously comparing the feedwater flow signal, the water level signal, the programmed level and the pressure compensated steam flow signal. In addition, the main turbine feedwater pump speed is varied to maintain a programmed pressure differential between the steam header and the feed pump discharge header. The speed controller continuously compares the actual ΔP with a programmed ΔP_{ref} which is a linear function of steam flow. Continued delivery of feedwater to the steam generators is required as a sink for the heat stored and generated in the reactor following a reactor trip and turbine trip. An override signal closes the feedwater valves when the average coolant temperature is below a given temperature and the reactor has tripped. Manual override of the feedwater control system is available at all times.

Block diagrams of the Steam Generator Water Level Control System and the Main Feedwater Pump Speed Control System are shown in Figures 7.7-6 and 7.7-7.

7.7.1.8 Steam Dump Control

The Steam Dump System in conjunction with the Rod Control System is designed to accept a 50 percent loss of net load without tripping the reactor.

The automatic Steam Dump System is able to accommodate this abnormal load rejection and to reduce the effects of the transient imposed upon the RCS. By bypassing main steam directly to the condenser an artificial load is thereby maintained on the primary system. The Rod Control System can then reduce the reactor temperature to a new equilibrium value without causing overtemperature and/or overpressure conditions. The steam dump steam flow capacity is greater than 40 percent of full load steam flow at full load steam pressure.

If the difference between the reference T_{avg} (T_{ref}) based on turbine first stage pressure and the lead-lag compensated average T_{avg} exceeds a pre-determined amount, and the interlock mentioned below is satisfied, a demand signal will actuate the steam dump to maintain the RCS temperature within control range until a new equilibrium condition is reached.

To prevent actuation of steam dump on small load perturbations, an independent load rejection sensing circuit is provided. This circuit senses the rate of decrease in the turbine load as detected by the turbine first stage pressure. It is provided to unblock the dump valves when the rate of load rejection exceeds a preset value corresponding to a 10 percent step load decrease or a sustained ramp load decrease of 5 percent/minute.

A block diagram of the Steam Dump Control System is shown on Figure 7.7-8.

7.7.1.8.1 Load Rejection Steam Dump Controller

This circuit prevents large increase in reactor coolant temperature following a large, sudden load decrease. The error signal is a difference between the lead-lag compensated average T_{avg} and the reference T_{avg} based on turbine first stage pressure.

The T_{avg} signal is the same as that used in the RCS. The lead-lag compensation for the T_{avg} signal is to compensate for lags in the plant thermal response and in valve positioning. Following a sudden load decrease, T_{ref} is immediately decreased and T_{avg} tends to increase, thus generating an immediate demand signal for steam dump. Since control rods are available, in this situation steam dump terminates as the error comes within the maneuvering capability of the control rods.

7.7.1.8.2 Plant Trip Steam Dump Controller

Following a reactor trip, as monitored by the reactor trip signal (P-4), the load rejection steam dump controller is defeated and the turbine trip steam dump controller becomes active. Since control rods are not available in this situation, the demand signal is the error signal between the lead-lag compensated average T_{avg} and the no-load reference T_{avg}. When the error signal exceeds a pre-determined setpoint the dump valves are tripped open in a prescribed sequence.

As the error signal reduces in magnitude (indicating that the RCS T_{avg} is being reduced toward the reference no-load value) the dump valves are modulated by the plant trip controller to regulate the rate of removal of decay heat and thus gradually establish the equilibrium hot shutdown condition.

7.7.1.8.3 Steam Header Pressure Controller

Residual heat removal is maintained by the steam generator pressure controller (manually selected) which controls the amount of steam flow to the condensers. This controller operates a portion of the same steam dump valves to the condensers which are used during the initial transient following turbine reactor trip on load rejection.

7.7.1.9 Incore Instrumentation

The Incore Instrumentation System consists of chromel-alumel thermocouples at fixed core outlet positions and movable miniature neutron detectors which can be positioned at the center of selected fuel assemblies, anywhere along the length of the fuel assembly vertical axis. The basic system for insertion of these detectors is shown in Figure 7.7-9.

7.7.1.9.1 Thermocouples

Chromel-alumel thermocouples are inserted into guide tubes that penetrate the reactor vessel head through seal assemblies, and terminate at the exit flow end of the fuel assemblies. The Unit 2 thermocouples are provided with two primary seals, a conoseal/grafoil seal and swage type seal from conduit to head. The Unit 1 thermocouples are provided with a grafoil seal and swage type seal from conduit to head. Thermocouple readings are monitored by the plant process/ERF computers. Information from the incore instrumentation is available even if the computers are not in service.

7.7.1.9.2 Movable Neutron Flux Detector Drive System

Miniature fission chamber detectors can be remotely positioned in retractable guide thimbles to provide flux mapping of the core. The stainless steel detector shell is brazed to the leading end of helical wrap drive cable and to stainless steel sheathed coaxial cable. The retractable thimbles, into which the miniature detectors are driven, are pushed into the reactor core through conduits which extend from the bottom of the reactor vessel down through the concrete shield area and then up to a thimble seal table. Their distribution over the core is nearly uniform with about the same number of thimbles located in each quadrant.

The thimbles are closed at the leading ends, are dry inside, and serve as the pressure barrier between the reactor water pressure and the atmosphere. Mechanical seals between the retractable thimbles and the conduits are provided at the seal table. During reactor operation, the retractable thimbles are stationary. They are extracted downward from the core during refueling to avoid interference within the core. A space above the seal table is provided for the retraction operation.

The drive system for the insertion of the miniature detectors consists basically of drive assemblies, five path rotary transfer assemblies, and 10 path rotary transfer assemblies, as shown in Figure 7.7-9. The drive system pushes hollow helical wrap drive cables into the core

with the miniature detectors attached to the leading ends of the cables and small diameter sheathed coaxial cables threaded through the hollow centers back to the ends of the drive cables. Each drive assembly consists of a gear motor which pushes a helical wrap drive cable and a detector through a selective thimble path by means of a special drive box and includes a storage device that accommodates the total drive cable length.

Manual isolation valves (one for each thimble) are provided for closing the thimbles. When closed, the valves form a 2500 pounds per square inch gage (psig) barrier. The manual isolation valves are not designed to isolate a thimble while a detector/drive cable is inserted into the thimble. The detector/drive cable must be retracted to a position above the isolation valve prior to closing the valve.

A small leak would probably not prevent access to the isolation valves and thus a leaking thimble could be isolated during a hot shutdown. A large leak might require cold shutdown for access to the isolation valve.

7.7.1.9.3 Control and Readout Description

The Control and Readout System provides means for inserting the miniature neutron detectors into the reactor core and withdrawing the detectors while plotting neutron flux versus detector position. The control system is located in the Control Room. Limit switches in each transfer device provide feedback of path selection operation. Each gear box drives an encoder for position feedback. One five path operation selector is provided for each drive unit to insert the detector in one of five functional modes of operation. One 10 path operation selector is also provided for each drive unit that is then used to route a detector into any one of up to 10 selectable paths. A common path is provided to permit cross calibration of the detectors.

The Control Room contains the necessary equipment for control, position indication, and flux recording for each detector.

A “flux-mapping” consists, briefly, of selecting (by panel switches) flux thimbles in given fuel assemblies at various core quadrant locations. The detectors are driven to the top of the core and stopped automatically. An x-y plot (position versus flux level) is initiated with the slow withdrawal of the detectors through the core from top to a point below the bottom. In a similar manner other core locations are selected and plotted. Each detector provides axial flux distribution data along the center of a fuel assembly.

Various radial positions of detectors are then compared to obtain a flux map for a region of the core.

The number and location of these thimbles have been chosen to permit measurement of local to average peaking factors to an accuracy of ±5 percent (95 percent confidence). Measured nuclear peaking factors will be increased by 5 percent to allow for this accuracy. If the measured power peaking is larger than acceptable, reduced power capability will be indicated.

Operating plant experience has demonstrated the adequacy of the incore instrumentation in meeting the design bases stated.

7.7.1.9.4 Power Distribution Monitoring System

An alternative to the Movable Incore Detector System for developing full core flux maps while above 25% power, is the BEACON Power Distribution Monitoring System (Reference 2). This system obtains data from the plant computer and processes the data into a 3-dimensional core model. The inputs to this system are core exit thermocouples, control rod bank position, Tcold, Reactor power level, and the nuclear instrumentation Power Range section signals. Per the Technical Requirements Manual, there is a minimum number of each type of input necessary to consider the system operable.

7.7.1.10 Boron Concentration Measurement System

The Boron Concentration Measurement System is abandoned in place.

7.7.1.11 Balance of Plant Systems

The following balance of plant control systems not required for safety are completely independent of any protective functions and as such can not impair the ability of the protection systems to function.

1. Condensate System (see Section 10.4.7).
2. Condensate Cleanup System (see Section 10.4.6).
3. Service Air System (see Section 9.3.1).
4. Instrument Air System (see Section 9.3.1).
5. Secondary Plant Sampling (see Section 10.4.16).
6. Water Treatment System (see Section 9.2.3).
7. H_2 and N_2 Supply System (see Section 10.4.15).
8. Potable and Sanitary Water System (see Section 9.2.4).
9. Heater Drains Systems (see Section 10.4.11).
10. Circulating Water Systems (see Section 10.4.5).
11. Turbine Plant Cooling Water Systems (see Section 10.4.12).
12. Turbine Building Area Ventilation System (see Section 9.4.4).
13. Condenser Evacuation System (see Section 10.4.2).
14. Turbine Gland Sealing System (see Section 10.4.3).
15. Steam Dump System (see Section 10.4.4).

16. Fire Protection System (see Section 9.5.1).

17. Turbine Generator (see Section 10.2).

18. Extraction Steam System (see Section 10.4.10).

19. Feedwater System (upstream of isolation valve) (see Section 10.4.7).

20. Steam Generator Blowdown System (see Section 10.4.8).

21. Auxiliary Steam System (see Section 10.4.13).

22. Main Steam System (downstream from first moment restraint after the isolation valve) (see Section 10.3.3).

23. Turbine Oil Purification System (see Section 10.4.14).

The following balance of plant control systems are not required for safety but have an interface with the protective system. The protective system function is assured for the following reasons:

1. Turbine Control System (see Section 7.2).

2. Plant Computer System

   The plant computer will monitor the status of the protection system. The inputs to the computer will be designed in accordance with the isolation criteria of the Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971.

   The terms “plant computer”, “process computer”, “plant process computer”, “Emergency Response Facility Computer System”, “ERFCS”, “TSC Data Display”, “EOF Data Display”, “Safety Parameter Display System”, “SPDS Computer System”, “SPDS display”, “SPDS”, and combinations of these terms refer to functions that are performed by digital computers and their associated data acquisition systems (DAS), analog-to-digital conversion equipment, alpha-numeric and/or graphical video display consoles, printers, keyboards, mass storage devices, telecommunications devices, and other peripheral equipment as required to accomplish the particular functions that are either required by regulation or have been provided to assist the operators in the monitoring of various processes during the operation of CPNPP Units 1 and 2. Except where specifically described, the use of these separate terms does not imply that separate, dedicated computer systems or equipment exist for the function associated with a particular term. The specific equipment used to accomplish particular functions is described in the associated Design Basis Documents (DBDs) which provide the engineering bases for the plant installed equipment.

3. Main feedwater pump control (see Section 7.7.1.7).

   The tripping of the main feedwater pump interacts with the protection system by starting the motor driven auxiliary feedwater pumps. The circuit is designed in accordance with IEEE Standard 279-1971 with the exception that the sensors and associated wiring being located by necessity in non-Seismic Category I structures will not be seismically qualified.

4. Blowdown and sample controls

The blowdown and sample isolation valves from the secondary side at the steam generator are closed on the start of the auxiliary feedwater pumps from the protection system. These actuation signals are designed in accordance with IEEE Standard 279-1971. Following a start of the Auxiliary Feedwater System, the sample system isolation valves may be reopened from the sample room by manually blocking the closing signal. This capability permits identification, and subsequent isolation, of a steam generator responsible for fission product transfer from the primary to the secondary system. Similarly, the blowdown system isolation valves may be reopened from the Control Room by manually blocking the closing signal, thereby enabling blowdown to the processing system.

7.7.1.12 Control Room Operating Console

The Control Room is the central operating location in a nuclear power station. It is from the Control Room that the plant operators control the NSSS, the turbine-generator systems, the auxiliary systems and the emergency systems. The Control Room operating console layout is a functional layout, based on operators' ease in relating the control board devices to the plant equipment and being able to determine, at a glance, the status of the equipment.

Figure 7.7-14A shows the arrangement of the Control Room panel. Figure 7.7-14 shows the functional layout of the control console. The chemical and volume control, nuclear instrumentation and rod control systems, systems that require almost continuous supervision during plant normal operation, are in the center of the "U" shaped consoles. Next to those systems are the pressurizer and main steam control systems. Far from the center are the auxiliary equipment that requires little supervision or will go in service automatically under emergency or accident conditions.

Due to the functional layout of the Control Room console, it is not possible to locate redundant controls in separate panels. Separation of redundant, safety-related controls is achieved by either a fire retardant material barrier or by maintaining a minimum 6 inch air separation. The Control Room horseshoe areas encompass two-tiered operating platforms that support operation of Plant Computer, Radiation Monitoring and Communication equipment.

The control switches and associated lights are furnished in enclosed metallic boxes (modules), which provide for physical protection of the switch, lights and internal wiring and for separation requirements between safety-related switches of redundant trains.

Redundant circuits which serve the same protective function enter the control board through separate apertures and terminate in separate terminal blocks.

Intra-panel wiring separation is achieved by providing 6 inch air separation between redundant train wiring or by separate enclosed metal wireways for redundant trains.

7.7.2 ANALYSIS

The plant control systems are designed to assure high reliability in any anticipated operational occurrences. Equipment used in these systems is designed and constructed with a high level of reliability.

Proper positioning of the control rods is monitored in the Control Room by bank arrangements of the individual position columns for each rod cluster control assembly. A rod deviation alarm alerts the operator of a deviation of one rod cluster control assembly from the other rod in that bank position. There are also insertion limit monitors with visual and audible annunciation. A rod bottom alarm signal is provided to the Control Room for each full length rod cluster control assembly. Four excore long ion chambers also detect asymmetrical flux distribution indicative of rod misalignment.

Overall reactivity control is achieved by the combination of soluble boron and rod cluster control assemblies. Long term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Short term reactivity control for power changes is accomplished by the Rod Control System which automatically moves rod cluster control assemblies. This system uses input signals including neutron flux, coolant temperature, and turbine load.

The axial core power distribution is controlled by moving the control rods through changes in RCS boron concentration. Adding boron causes the rods to move out thereby reducing the amount of power in the bottom of the core, this allows power to redistribute toward the top of the core. Reducing the boron concentration causes the rods to move into the core thereby reducing the power in the top of the core, the result redistributes power towards the bottom of the core.

The plant control systems will prevent an undesirable condition in the operation of the plant that, if reached, will be protected by reactor trip. The description and analysis of this protection is covered in Section 7.2. Worst case failure modes of the plant control systems are postulated in the analysis of off-design operational transients and accidents covered in Chapter 15 such as the following:

1. Uncontrolled rod cluster control assembly bank withdrawal from a subcritical or low power startup condition.

2. Uncontrolled rod cluster control assembly bank withdrawal at power.

3. Rod cluster control assembly misalignment.

4. Loss of external electrical load.

5. Turbine trip.

6. Loss of all non-emergency AC power to the station auxiliaries.

7. Feedwater system malfunctions that result in a decrease in feedwater temperature.

8. Excessive increase in secondary steam flow.

9. Inadvertent opening of a steam generator relief or safety valve.

These analyses show that a reactor trip setpoint is reached in time to protect the health and safety of the public under those postulated incidents and that the resulting coolant temperatures produce a DNBR well above the limit value. Thus, there is no cladding damage and no release

of fission products to the RCS under the assumption of these postulated worst case failure modes of the Plant Control System.

7.7.2.1 Separation of Protection and Control System

In some cases, it is advantageous to employ control signals derived from individual protection channels through isolation amplifiers contained in the protection channel. As such, a failure in the control circuitry does not adversely affect the protection channel. Test results have shown that a short circuit or the application (credible fault voltage from within the cabinets) of 118 volt AC or 140 volt DC on the isolated output portion of the circuit (nonprotection side of the circuit) will not affect the input (protection) side of the circuit.

Where a single random failure can cause a control system action that results in a generating station condition requiring protective action and can also prevent proper action of a protection system channel designed to protect against the condition, the remaining redundant protection channels are capable of providing the protective action even when degraded by a second random failure. This meets the applicable requirements of Section 4.7 of IEEE Standard 279-1971.

The pressurizer pressure channels needed to derive the control signals are electrically isolated from control.

7.7.2.2 Response Considerations of Reactivity

Reactor shutdown with control rods is completely independent of the control functions since the trip breakers interrupt power to the full length rod drive mechanisms regardless of existing control signals. The design is such that the system can withstand accidental withdrawal of control groups or unplanned dilution of soluble boron without exceeding acceptable fuel design limits. The design meets the requirements of the 1971 General Design Criterion 25.

No single electrical or mechanical failure in the Rod Control System could cause the accidental withdrawal of a single rod cluster control assembly from the partially inserted bank at full power operation. The operator could deliberately withdraw a single rod cluster control assembly in the control bank; this feature is necessary in order to retrieve a rod, should one be accidentally dropped. In the extremely unlikely event of simultaneous electrical failures which could result in single rod cluster control assembly withdrawal, rod deviation would be displayed on the plant annunciator, and the individual rod position readouts would indicate the relative positions of the rods in the bank. Withdrawal of a single rod cluster control assembly by operator action, whether deliberate or by a combination of errors, would result in activation of the same alarm and the same visual indications.

Each control bank and shutdown bank A and B is divided into two groups (group 1 and group 2) and shutdown banks C, D, and E have one group (group 1). Each group can have up to four mechanisms each. The rods comprising a group operate in parallel through multiplexing thyristors. The two groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. The group 1 and group 2 power circuits are installed in different cabinets as shown in Figure 7.7-15, which also shows that one group is always within one step (5/8 inch) of the other group. A definite schedule of actuation or deactuation of the stationary gripper, moveable gripper, and lift coils of a mechanism is required to withdraw the rod cluster control assembly attached to the mechanism. Since the four stationary grippers,

moveable grippers, and lift coils associated with the rod cluster control assemblies of a rod group are driven in parallel, any single failure which could cause rod withdrawal would affect a minimum of one group of rod cluster control assemblies. Mechanical failures are in the direction of insertion, or immobility.

Figure 7.7-16 is provided for a discussion of design features that assure that no single electrical failure could cause the accidental withdrawal of a single rod cluster control assembly from the partially inserted bank at full power operation.

The Figure 7.7-16 shows the typical parallel connections on the lift, movable and stationary coils for a group of rods. Since single failures in the stationary or movable circuits will result in dropping or preventing rod (or rods) motion, the discussion of single failure will be addressed to the lift coil circuits. 1) Due to the method of wiring the transformers which turn on the lift coil multiplex thyristors, three of the four thyristors in a rod group could remain turned off when required to turn on, if for example the gate signal lead failed open at point X_1. Upon “up” demand, one rod in group 1 and 4 rods in group 2 would withdraw. A second failure at point X_2 in the group 2 circuit is required to withdraw one rod cluster control assembly; 2) Timing circuit failures will affect the four mechanisms of a group or the eight mechanisms of the bank and will not cause a single rod withdrawal; 3) More than two simultaneous component failures are required (other than the open wire failures) to allow withdrawal of a single rod.

The identified multiple failure involving the least number of components consists of open circuit failure of the proper two out of 16 wires connected to the gate of the lift coil thyristors. The probability of open wire (or terminal) failure is 0.016×10^{-6} per hour by MIL-HDB-217A. These wire failures would have to be accompanied by failure, or disregard, of the indications mentioned above. The probability of this occurrence is therefore too low to have any significance.

Concerning the human element, to erroneously withdraw a single rod cluster control assembly, the operator would have to improperly set the bank selector switch, the lift coil disconnect switches, and the “in-hold-out” lever. In addition, the three indications would have to be disregarded or ineffective. Such series of errors would require a complete lack of understanding and administrative control. A probability number cannot be assigned to a series of errors such as these.

The DRPIS provides direct visual displays of each control rod assembly position. The plant computer alarms for deviation of rods from their banks. In addition a rod insertion limit monitor provides an audible and visual alarm to warn the operator of an approach to an abnormal condition due to dilution. The low-low insertion limit alarm alerts the operator to follow emergency boration procedures. The facility reactivity control systems are such that acceptable fuel damage limits will not be exceeded even in the event of a single malfunction of either system.

An important feature of the Control Rod System is that insertion is provided by gravity fall of the rods.

In all analyses involving reactor trip, the single, highest worth rod cluster control assembly is postulated to remain untripped in its full out position.

One means of detecting a stuck control rod assembly is available from the actual rod position information displayed on the control board. The control board position readouts, one for each full length rod, give the plant operator the actual position of the rod in steps. The indications are grouped by banks (e.g., control bank A, control bank B, etc.) to indicate to the operator the deviation of one rod with respect to other rods in a bank. This serves as a means to identify rod deviation.

The plant computer monitors the actual position of all rods. Should a rod be misaligned from the other rods in that bank by more than 12 steps, the rod deviation alarm is actuated.

Misaligned rod cluster control assemblies are also detected and alarmed in the Control Room via the flux tilt monitoring system which is independent of the plant computer.

Isolated signals derived from the Nuclear Instrumentation System are compared with one another to determine if a preset amount of deviation of average power level has occurred. Should such a deviation occur, the comparator output will operate a bistable unit to actuate a control board annunciator. This alarm will alert the operator to a power imbalance caused by a misaligned rod. By use of individual rod position readouts, the operator can determine the deviating control rod and take corrective action. The design of the plant control systems meets the requirements of the 1971 General Design Criterion 23.

Refer to Section 4.3 for additional information on response considerations due to reactivity.

7.7.2.3 Step Load Changes Without Steam Dump

The Rod Control System restores equilibrium conditions, without a trip, following a plus or minus 10 percent step change in load demand, over the 15 to 100 percent power range for automatic control. Steam dump is blocked for load decrease less than or equal to 10 percent.

The Rod Control System minimizes the reactor coolant average temperature deviation during the transient within a given value and restores average temperature to the programmed setpoint. Excessive pressurizer pressure variations are prevented by using spray and heaters and power relief valves in the pressurizer.

The control system must limit nuclear power overshoot to acceptable values following a 10 percent increase in load to 100 percent.

7.7.2.4 Loading and Unloading

Ramp loading and unloading of 5 percent per minute can be accepted over the 15 to 100 percent power range under automatic control without tripping the plant. The function of the control system is to maintain the coolant average temperature as a function of turbine-generator load.

The coolant average temperature increases during an unloading transient and causes a continuous insurge to the pressurizer as a result of coolant expansion. The sprays limit the resulting pressure increase. Conversely, as the coolant average temperature is decreasing during a loading transient, there is a continuous outsurge from the pressurizer resulting from coolant contraction. The pressurizer heaters limit the resulting system pressure decrease. The pressurizer water level is programmed such that the water level is above the setpoint for heater cut out during the loading and unloading transients. The primary concern during loading is to

limit the overshoot in nuclear power and to provide sufficient margin in the Overtemperature N-16 setpoint.

The automatic load controls are designed to adjust the unit generation to match load requirements within the limits of the unit capability and licensed rating.

During rapid loading transients, a drop in reactor coolant temperature is sometimes used to increase core power. This mode of operation is applied when the control rods are not inserted deeply enough into the core to supply all the reactivity requirements of the rapid load increase (the boron control system is relatively ineffective for rapid power changes). The reduction in temperature is initiated by continued turbine loading past the point where the control rods are completely withdrawn from the core. The temperature drop is recovered and nominal conditions restored by a boron dilution operation.

Excessive drops in coolant temperature are prevented by interlock C-16. This interlock circuit monitors the auctioneered low coolant temperature indications and the programmed reference temperature which is a function of turbine first stage pressure and causes a turbine loading stop when the temperature difference reaches the setpoint.

The core axial power distribution is controlled during the reduced temperature return to power by placing the control rods in the manual mode when the operating limits are approached. Placing the rods in manual will stop further changes in axial flux imbalance due to rod motion and it will also initiate the required drop in coolant temperature. Normally power distribution control is not required during a rapid power increase and the rods will proceed, under the automatic rod control system, to the top of the core. The bite position is reestablished at the end of the transient by decreasing the coolant boron concentration.

7.7.2.5 Load Rejection Furnished by the Steam Dump System

When a load rejection occurs, if the difference between the required temperature setpoint of the RCS and the actual average temperature exceeds a predetermined amount, a signal will actuate the steam dump to maintain the RCS temperature within control range until a new equilibrium condition is reached.

The reactor power is reduced at a rate consistent with the capability of the Rod Control System. Reduction of the reactor power is automatic. The steam dump flow reduction is as fast as rod cluster control assemblies are capable of inserting negative reactivity.

The Rod Control System can then reduce the reactor temperature to a new equilibrium value without causing overtemperature and/or overpressure conditions. The design steam dump steam flow capacity is 40 percent of full load steam flow at full load steam pressure.

The steam dump flow reduces proportionally as the control rods act to reduce the average coolant temperature. The artificial load is therefore removed as the coolant average temperature is restored to its programmed equilibrium value.

The dump valves are modulated by the reactor coolant average temperature signal. The required number of steam dump valves can be tripped quickly to stroke full open or modulate, depending upon the magnitude of the temperature error signal resulting from loss of load.

7.7.2.6 Turbine-Generator Trip with Reactor Trip

Whenever the turbine-generator unit trips at an operating power level above 50 percent power, the reactor also trips. The unit is operated with a programmed average temperature as a function of load, with the full load average temperature significantly greater than the equivalent saturation pressure of the steam generator safety valve setpoint. The thermal capacity of the RCS is greater than that of the secondary system, and because the full load average temperature is greater than the no-load temperature, a heat sink is required to remove heat stored in the reactor coolant to prevent actuation of steam generator safety valves for a trip from full power. This heat sink is provided by the combination of controlled release of steam to the condenser and by makeup of feedwater to the steam generators.

The Steam Dump System is controlled from the reactor coolant average temperature signal whose setpoint values are programmed as a function of turbine load. Actuation of the steam dump is rapid to prevent actuation of the steam generator safety valves. With the dump valves open, the average coolant temperature starts to reduce quickly to the no-load setpoint. A direct feedback of temperature acts to proportionally close the valves to minimize the total amount of steam which is bypassed.

Following the turbine trip, the feedwater flow is cut off when the average coolant temperature decreases below a given temperature or when the steam generator water level reaches a given high level.

Additional feedwater makeup is then controlled manually to restore and maintain steam generator water level while assuring that the reactor coolant temperature is at the desired value. Residual heat removal is maintained by the steam header pressure controller (manually selected) which controls the amount of steam flow to the condensers. This controller operates a portion of the same steam dump valves to the condensers which are used during the initial transient following turbine and reactor trip.

The pressurizer pressure and level fall rapidly during the transient because of coolant contraction. The pressurizer water level is programmed so that the level following the turbine and reactor trip is above the heaters. However, if the heaters become uncovered following the trip, the Chemical and Volume Control System will provide full charging flow to restore water level in the pressurizer. Heaters are then turned on to restore pressurizer pressure to normal.

The steam dump and feedwater control systems are designed to prevent the average coolant temperature from falling below the programmed no load temperature following the trip to ensure adequate reactivity shutdown margin.

REFERENCES

1. Lipchak, J. B. and Stokes, R. A., “Nuclear Instrumentation System,” WCAP-8255, January 1974.

2. WCAP-12472-P-A, “BEACON Core Monitoring and Operations Support System,” August 1994.

TABLE 7.7-1
PLANT CONTROL SYSTEM INTERLOCKS

(Sheet 1 of 2)

Designation	Derivation	Function
C-1	1/2 neutron flux (intermediate range) above setpoint	Blocks automatic and manual control rod withdrawal
C-2	1/4 neutron flux (power range) above setpoint	Blocks automatic and manual control rod withdrawal
C-3	2/4 Overtemperature N-16 above setpoint	Blocks automatic and manual control rod withdrawal
		Actuates turbine runback via load reference
		Defeats remote load dispatching (if remote load dispatching is used)
C-4	2/4 Overpower N-16 above setpoint	Blocks automatic and manual control rod withdrawal
		Actuates turbine runback via load reference
		Defeats remote load dispatching (if load dispatching is used)
C-5	1/1 turbine impulse chamber pressure below setpoint	Defeats remote load dispatching (if load dispatching is used)
		Blocks automatic control rod withdrawal
C-7	1/1 time derivative (absolute value) of turbine impulse chamber pressure (decrease only) above setpoint	Makes steam dump valves available for either tripping or modulation
C-8	Turbine trip, 2/3 turbine emergency trip fluid pressure below setpoint	Input signal to non-NSSS turbine/ generator trip logic
	or	
	4/4 turbine valves closed	

TABLE 7.7-1
PLANT CONTROL SYSTEM INTERLOCKS

(Sheet 2 of 2)

Designation	Derivation	Function
C-9	Any condenser pressure above setpoint, or 3/4 circulation water pump breakers open	Blocks steam dump to condenser
C-11	1/1 bank D control rod position above setpoint	Blocks automatic rod withdrawal
C-16	Reduced limit in coolant temperature above normal setpoint	Stops automatic turbine loading until condition clears
C-20	2/2 Turbine Impulse Chamber Pressure	Arms AMSAC; below setpoint blocks AMSAC (See FSAR Section 7.8)

TABLE 7.7-2
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7.8 ATWS MITIGATION SYSTEM ACTUATION CIRCUITRY (AMSAC)

7.8.1 DESCRIPTION

7.8.1.1 System Description

The ATWS (Anticipated Transient Without Scram) Mitigation System Actuation Circuitry (AMSAC) provides a backup to the Reactor Trip System (RTS) and ESF Actuation System (ESFAS) for initiating turbine trip and auxiliary feedwater flow in the event an anticipated transient results (e.g., the complete loss of main feedwater). The AMSAC is independent of and diverse from the Reactor Trip System and the ESF Actuation System with the exception of the analog steam generator level and turbine first stage pressure inputs, and the final actuation devices. It is a highly-reliable, microprocessor-based, non-safety related circuitry.

The AMSAC continuously monitors level in the steam generators, which is an anticipatory indication of a loss of heat sink. AMSAC initiates certain functions when the level drops below a predetermined setpoint for a preselected time and for three of the four steam generator levels. These initiated functions are turbine trip, auxiliary feedwater initiation, and steam generator blowdown and sample lines isolation.

The AMSAC is designed to be highly reliable, resistant to inadvertent actuation, and easily maintained. Reliability is assured through the use of internal redundancy and continual self-testing within the system. Inadvertent actuations are minimized through the use of internal redundancy and majority voting at the output stage of the system. The time delay on low steam generator level and the coincidence logic also minimize inadvertent actuations.

The AMSAC automatically performs its actuations when the plant is above a preselected power level which is determined using turbine impulse chamber pressure. This signal remains armed sufficiently long after the pressure drops below the setpoint to ensure that its function will be performed in the event of a turbine trip.

7.8.1.2 Equipment Description

The AMSAC equipment is located in a seismically qualified cabinet.

The design of the AMSAC is based on the industry standard Intel multibus format, which permits the use of various readily available and widely used microprocessor cards on a common data bus for various functions.

The AMSAC consists of the following:

1. Steam Generator (SG) Level

   SG level is measured with four existing differential pressure-type level transmitters, for each of the main steam generators.

2. Turbine First State Pressure

   Turbine First Stage Pressure is measured with two existing pressure transmitters located in the steam supply line near the turbine.

3. System Hardware

The system hardware consists of two primary systems: the Actuation Logic System (ALS) and the Test/Maintenance System (T/MS).

Actuation Logic System

The ALS monitors the analog inputs, performs the required functional logic, provides actuation outputs to trip the turbine and initiate auxiliary feedwater flow, and provides status information to the Test/Maintenance System. The ALS consists of three groups of input/output (I/O) modules, three actuation logic processors (ALPs), two majority voting modules, and two output relay panels. The I/O modules provide signal conditioning, isolation, and test features for interfacing between the ALS and T/MS. Conditioned signals are sent to three identical ALPs for analog-to-digital conversion, setpoint comparison, and coincidence logic performance. Each of the ALPs perform identical logic calculations using the same inputs and derive component actuation demands, which are then sent to the majority voting modules. The majority voting modules perform a two-out-of-three vote on the ALP demand signals. These modules drive the relays providing outputs to the existing turbine trip and auxiliary feedwater initiation circuits. A simplified block diagram of the AMSAC ALS architecture is presented in Figure 7.8-1.

Test/Maintenance System

The Test/Maintenance System provides the AMSAC with automated and manual testing as well as a maintenance mode. Automated testing is the continuously performed self-check done by the system during normal operation. ALS status is monitored by the T/MS and sent to the plant computer and the main control board. Manual testing of the system by the maintenance staff can be performed on-line to provide assurance that the ALS system is fully operational. The maintenance mode permits the maintenance staff, under administrative control, to modify channel setpoints, channel status and timer values, and initiate channel calibration.

The T/MS consists of a test/maintenance processor, a digital-to- analog conversion board, a memory board, expansion boards, a self-health board, digital output modules, a test/maintenance panel, and a portable terminal/printer.

4. Equipment Actuation

The output relay panels provide component actuation signals through the isolation relays. These signals drive the final actuation circuitry for auxiliary feedwater initiation and turbine trip. Existing actuation devices of the component are used.

7.8.1.3 Functional Performance Requirements

The AMSAC automatically initiates auxiliary feedwater, trips the turbine, and isolates steam generator blowdown and sampling lines. Analyses have shown that the most limiting ATWS event is a loss of feedwater event without a reactor trip. Therefore, AMSAC performs the following mitigative actuations:

1. Ensures a secondary heat sink following an anticipated transient (ANS Condition II) without a reactor trip.

2. Limits core damage following an anticipated transient without a reactor trip.

3. Ensures that the energy generated in the core is compatible with the design limits to protect the reactor coolant pressure boundary by maintaining the reactor coolant pressure to within ASME Stress Level C.

7.8.1.4 AMSAC Interlocks

A single interlock, designated as C-20 (See Table 7.7-1), is provided to allow for the automatic arming and blocking of the AMSAC. The system is blocked at sufficiently low reactor power levels when the actions taken by the AMSAC following an ATWS need not be automatically initiated. Turbine impulse chamber pressure in a two-out-of-two logic scheme is used for this permissive. Turbine impulse chamber pressure above the setpoint will automatically defeat any block, i.e., will arm the AMSAC. Dropping below this setpoint will automatically block the AMSAC. Removal of the C-20 permissive is automatically delayed for a predetermined time. The operating status of the AMSAC is displayed on the main control board.

7.8.1.5 Steam Generator Level Sensor Arrangement

SG level is determined by a differential pressure transmitter, measuring the level drop in the steam generator. These SG level signals are used as inputs to the AMSAC and are isolated signals from the Process Protection Cabinets.

7.8.1.6 Turbine Impulse Chamber Pressure Arrangement

Turbine impulse chamber pressure is determined by a pressure transmitter, measuring the pressure rise in the turbine. These pressure signals are used as input into AMSAC and are isolated signals from the Process Protection Cabinets.

7.8.1.7 Trip System

The differential pressure that is measured in the steam generator is used by the AMSAC to determine trip demand. Signal conditioning is performed on the transmitter output and used by each of the ALPs to derive a component actuation demand. If three of the four steam generators have a low level at a power level greater than the C-20 permissive, then a trip demand signal is generated. This signal drives output relays for performing the necessary mitigative actions.

7.8.1.8 Isolation Devices

AMSAC is independent of the Reactor Trip (RTS) and Engineered Safety Features Actuation Systems (ESFAS). The AMSAC inputs for measuring turbine impulse chamber pressure and narrow range steam generator water level are derived from existing transmitters and channels within the Process Protection System. Connections to these channels are made downstream of Class 1E isolation devices which are located within the Process Protection Cabinets. These isolation devices ensure that the existing protection system continues to meet all applicable safety criteria. Buffering of the AMSAC outputs from the safety related final actuation device circuits is achieved through Class 1E isolation relays located within the AMSAC cabinet. A

credible fault occurring in the nonsafety-related AMSAC will not propagate through and degrade the RTS and ESFAS.

7.8.1.9 AMSAC Diversity from the Reactor Trip and Engineered Safety Features Actuation System

The AMSAC utilizes equipment diverse from the RTS and ESFAS to prevent common mode failures that might affect the AMSAC and the RTS or ESFAS. The AMSAC is a digital, microprocessor-based system with the exception of the analog SG level and turbine impulse pressure transmitter inputs. The reactor trip system utilizes an analog based protection system. Also where similiar components are utilized for the same function in both AMSAC and the reactor trip system, the components used in AMSAC are provided from a different manufacturer.

Common mode failure of identical components in the analog portion of the Reactor Protection System (RPS) that could result in the inability of the system to generate a reactor trip signal, will not impact the ability of the digital AMSAC to generate its required mitigative functions. Similarly, a postulated common mode failure affecting analog components in ESFAS, which could affect its ability to initiate auxiliary feedwater, will not impact the ability of the digital based AMSAC to automatically initiate auxiliary feedwater.

7.8.1.10 Power Supply

The AMSAC power supply is a non-Class 1E Uninterruptable AC Power Supply (UPS) source, and battery backed. The AMSAC is an energize-to-actuate system capable of performing its mitigative functions with a loss of offsite power.

7.8.1.11 Environmental Variations

AMSAC equipment is not designed as safety-related equipment with the exception of the output isolation relays. Therefore, AMSAC is not fully required to be qualified as safety related. The AMSAC equipment is located in a controlled environment such that variations in the ambient conditions are minimized. No AMSAC equipment is located inside containment. The transmitters (steam generator level and turbine impulse chamber pressure) that supply the input into AMSAC are located inside containment and the turbine building, respectively.

7.8.1.12 Setpoints

The AMSAC makes use of two setpoints in the coincidence logic to determine if mitigative functions are required. Water level in each steam generator is sensed to determine if a loss of secondary heat sink is imminent. The low level setpoint is selected in such a manner that a true lowering of the level will be detected by the system. The normal small variations in steam generator level will not result in a spurious AMSAC signal.

The C-20 permissive setpoint is selected in order to be consistent with ATWS investigations showing that the mitigative actions performed by the AMSAC need not be automatically actuated below a certain power level. The maximum allowable value of the C-20 permissive setpoint is defined by these investigations.

To avoid inadvertent AMSAC actuation on the complete loss of main feedwater, AMSAC actuation is delayed by a preselected time. This will ensure the Reactor Trip System will provide the first trip signal.

To ensure that the AMSAC remains armed sufficiently long to permit its function in the event of a turbine trip, the C-20 permissive is maintained for a preset time delay after the turbine impulse chamber pressure drops below the setpoint.

The AMSAC setpoints and setpoint modifications are administratively controlled.

7.8.2 ANALYSIS

7.8.2.1 Safety Classification/Safety-Related Interface

The AMSAC is not a safety-related system and therefore need not meet the requirements of IEEE 279-1971. The AMSAC has been implemented such that the Reactor Trip System and the ESF Actuation System continue to meet all applicable safety-related criteria. The AMSAC is independent of the RTS and ESFAS. The isolation provided, between the RTS and the AMSAC and between the ESFAS and the AMSAC, by the isolator modules and the isolation relays ensures that the applicable safety-related criteria are met for the RTS and the ESFAS.

7.8.2.2 Redundancy

Since AMSAC is a backup non-safety related system to the redundant RPS, redundancy is not required. To ensure high system reliability, portions of the AMSAC have been implemented as internally redundant, such that a single failure of an input channel or ALP will neither actuate not prevent actuation of the AMSAC.

7.8.2.3 Diversity from the Existing Trip System

Diverse equipment has been selected in order that common mode failures affecting both the RTS and the AMSAC or both the ESFAS and the AMSAC will not render these systems inoperable simultaneously. A more detailed discussion of the diversity, between the RTS and the AMSAC and between the ESFAS and the AMSAC, is presented in Section 7.8.1.9.

7.8.2.4 Electrical Independence

The AMSAC is electrically independent of the RTS and ESFAS from the sensor output up to but not including the final actuation devices. Isolation devices are provided to isolate the non-safety AMSAC circuitry from the safety-related input sensors and actuation circuits of the auxiliary feedwater system.

7.8.2.5 Physical Separation from the RTS and ESFAS

AMSAC is physically separated from the existing protection system hardware. The AMSAC outputs are provided from separate relay panels within the cabinets. The three trains (non-1E Train C, 1E Train A, and 1E Train B) are separated within the AMSAC cabinet by a combination of metal barriers, conduit and distance.

7.8.2.6 Environmental Qualification

Equipment related to the AMSAC is qualified to operate under conditions resulting from anticipated operational occurrences for the respective equipment location. The AMSAC equipment, with the exception of the isolation devices, located outside containment in a mild environment follows the same design standard that currently exists for non-class 1E equipment.

7.8.2.7 Seismic Qualification

It is required that only the isolation devices comply with seismic qualification. The AMSAC output isolation device which is located within the AMSAC cabinet, is qualified in accordance with the requirements of IEEE Standard 344-1975, “IEEE Standard for Seismic Qualification of Class 1E Electrical Equipment for Nuclear Power Generating Stations”.

7.8.2.8 Test, Maintenance, and Surveillance Quality Assurance

The quality assurance requirements for testing, maintenance, and surveillance of the AMSAC are, at a minimum, consistent with plant procedures for quality related equipment. Specific quality assurance requirements are defined by the procurement specification for inspections, examinations, storage, shipment, and testing of the AMSAC.

Acceptance testing and program validation of the AMSAC was completed prior to shipment. Functional testing of the system was conducted as part of the preoperational test program. Periodic testing will be performed both automatically through the use of the system automatic self-checking capability, and manually via the AMSAC test/maintenance panel in accordance with plant procedures.

7.8.2.9 Testability at Power

The AMSAC is testable at power. This testing is done via the system test/maintenance panel. The capability of the AMSAC to perform its mitigative actuations is bypassed at a system level while in the test mode. Total system testing is performed as a set of three sequential, partial, overlapping tests. The first of the tests checks the analog input portions of the AMSAC in order to verify accuracy. Each of the analog input modules is checked separately. The second test checks each of the ALPs to verify that the appropriate coincidence logic is sent to the majority voter. Each ALP is tested separately. The last test exercises the majority voter and the integrity of the associated output relays. The majority voter and associated output relays are tested by exercising all possible input combinations to the majority voter. The integrity of each of the output relays is checked by confirming continuity of the relay coils without operating the relays. The capability to individually operate the output relays confirm the integrity of the associated field wiring. Operation of the corresponding isolation relays and final actuation devices at plant shutdown is provided.

7.8.2.10 Inadvertent Actuation

The AMSAC is designed such that the frequency of inadvertent actuations is minimized. This high reliability is ensured through use of three redundant ALPs and a majority voting module. A single failure in any of these modules will not result in a spurious AMSAC actuation. In addition, the three-out-of-four low steam generator level coincidence logic and time delay minimize the potential for inadvertent actuations.

7.8.2.11 Maintenance Bypasses

The AMSAC is blocked at the system level during maintenance, repair, calibration or testing. While the system is blocked, the bypass conditions is continuously indicated on the main control board.

7.8.2.12 Operating Bypasses

The AMSAC has been designed to allow for operational bypasses with the inclusion of the C-20 permissive. Above the C-20 setpoint, the AMSAC is automatically unblocked (i.e., armed); below the setpoint, the system is automatically blocked. The operating status of the AMSAC is continuously indicated on the main control board via an annunciator window.

7.8.2.13 Indication of Bypasses

Whenever the mitigative capabilities of the AMSAC are bypassed or deliberately rendered inoperable, this condition is continuously indicated on the main control board. In addition to the operating bypass, any manual maintenance bypass is indicated via the AMSAC general warning that is sent to the main control board.

7.8.2.14 Means for Bypassing

A permanently installed system bypass selector switch is provided to bypass the system. This is a two-position selector switch with “NORMAL” and “BYPASS” positions. At no time is it necessary to use any temporary means, such as installing jumpers or pulling fuses, to bypass the system.

7.8.2.15 Completion of Mitigative Actions Once Initiated

The AMSAC mitigative actions are initiated when the coincidence logic is satisfied and the time delay requirements are met. If the flow in the feedwater lines is re-initiated before the timer expires and the SG water level increases to above the low low setpoint, then the coincidence logic will no longer be satisfied and the actuation signal disappears. If the coincidence logic conditions are maintained for the duration of the time delay, then the mitigative actions are initiated. The auxiliary feedwater initiation signal is latched in at the component actuating devices and the turbine trip is latched at the turbine electro-hydraulic control system. Deliberate operator action is then necessary to terminate auxiliary feedwater flow, clear the turbine trip signal using the main control board turbine trip reset switch, and proceed with the reopening of the turbine stop valves.

7.8.2.16 Manual Initiation

Manual initiation of the AMSAC is not provided. The capability to initiate the AMSAC mitigative functions manually, i.e., initiate auxiliary feedwater, trip the turbine, and isolate steam generator blowdown and sampling lines, exists at the main control board.

7.8.2.17 Information Readout

The AMSAC has been designed such that the operating and maintenance staffs have accurate, complete and timely information pertinent to the status of the AMSAC. A system level general

warning alarm is indicated in the control room. Diagnostic capability exists from the test/maintenance panel to determine the cause of any unanticipated inoperability or deviation.

7.8.3 COMPLIANCE WITH STANDARDS AND DESIGN CRITERIA

The AMSAC meets the applicable requirements of Part 50.62 of Title 10 of the Code of Federal Regulations and the quality assurance requirements of NRC Generic Letter 85-06.

8.0 ELECTRIC POWER

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8.1 INTRODUCTION

8.1.1 UTILITY GRID DESCRIPTION

The Texas Reliability Entity (TRE) is one of 8 regional reliability councils in the North American Electric Reliability Corporation (NERC). As a NERC member, the primary responsibility of the TRE is to facilitate reliable power grid operations in the Electric Reliability Council of Texas (ERCOT) region. ERCOT is the Independent System Operator (ISO) of the ERCOT Transmission Grid (Grid).

ERCOT is located entirely within Texas; consequently, the Public Utility Commission of Texas (PUCT) is ERCOT's principal regulatory authority. A Board of Directors, made up of members from each of ERCOT's electricity market groups, together with independent members, governs ERCOT.

ERCOT oversees the operation of the Grid and manages the activities related to the electric industry. ERCOT is the regional security coordinator for the ERCOT Grid and is responsible for operating the ERCOT Grid and the ERCOT Control Area in compliance with good utility practice, NERC standards, ERCOT Operating Guides and ERCOT Protocols, and individual Transmission/Distribution Service Provider (TDSP) limitations. Transmission Operator (TO) System Operations Center works with ERCOT and carries out dispatch instructions directly or on behalf of ERCOT.

TO is the transmission owner and transmission planner for CPNPP area. TO's transmission system is an integrated part of ERCOT system and TO maintains it's transmission system in conformance with the ERCOT Operating Guides and ERCOT Protocols.

The TO transmission systems consist of 345-kV lines for bulk supply and includes 138-kV and 69-kV lines to transmit power to load-serving substations. Composition of generation sources connected to the TO transmission system include fossil fuel plants (lignite, gas/oil,) and the CPNPP nuclear plant (interconnected).

The CPNPP output is connected to the 345-kV transmission system via the TO's CPNPP 345-kV switchyard. The startup and shutdown power for the units are derived from the 138-kV and 345-kV switchyards as described in Section 8.2.

8.1.2 ONSITE ELECTRIC SYSTEM DESCRIPTION

The onsite electric system includes power supplies, distribution equipment, and instrumentation and control to supply power to the unit auxiliary loads (normal and safety-related) during startup, normal operation, and normal and emergency shutdown. Connection of the generator outputs to the 345-kV switchyard is via isolated-phase bus (generator main leads), step-up transformers, and transmission lines.

Power to the unit 6900-V auxiliary bus systems is furnished through either the unit auxiliary, station service or startup transformers.

Normally, the non-safety-related auxiliaries are supplied by the main generators through the unit auxiliary transformers. These transformers are connected to the main generator leads, between

the generator and main transformers, by means of isolated-phase bus. Safety-related auxiliaries are normally supplied by the preferred offsite power systems.

Two separate and physically independent startup transformers provide startup, preferred and alternate shutdown power to the safety-related auxiliaries of the units on an immediate basis. One transformer is connected to the 345-kV switchyard while the second transformer is connected to the 138-kV switchyard; these transformers are connected to the safety-related 6900-V auxiliary bus systems and, as such, provide two independent means of supplying the safety-related equipment from the offsite power system without relying on the main generator.

Two station service transformers provide power to the non-safety-related auxiliaries. These transformers are connected to the 345-kV switchyard. One transformer is connected to the non-safety-related 6900-V auxiliary buses of one unit while the second transformer is connected to the non-safety-related 6900-V buses of the other unit.

In addition, the 25-kV Plant Support Power Loop, fed from the 138-kV switchyard, supplies power to non-safety-related equipment. The 25-kV Plant Support Power Loop also supplies alternate power (through manual transfer switches) to certain essential equipment in plant Modes 5 and 6 during safety-related bus outages.

Upon loss of all Offsite AC power, station standby power sources, consisting of four diesel generators (two per unit) are provided to satisfy the loading requirements of the AC safety-related loads. System redundancy precludes loss of all onsite power as a result of any single failure.

The DC safety-related loads of each unit are supplied by four independent Class 1E 125-VDC battery systems, which are divided into two redundant trains. The DC loads that are non-safety-related receive power through independent 125/250-VDC, 125-VDC, and 24/48-VDC battery systems. Switchyard DC load requirements are supplied by independent systems located in each switchyard. The AC and DC safety-related loads of each unit are divided into redundant load groups, each energized from an independent emergency power supply. There are no interconnections between redundant load groups.

8.1.3 SAFETY-RELATED LOADS

The safety-related loads that require electric power to perform their safety functions are identified in Table 8.1-1. This table includes the safety load, safety functions performed, and type of electric power (AC or DC, or both).

8.1.4 DESIGN CRITERIA

The design bases, criteria, NRC regulatory guides, standards, and other documents that are implemented in the design of the safety-related systems (as discussed in Sections 8.2 and 8.3) are listed as follows:

8.1.4.1 United States Code of Federal Regulations Title 10, Energy (10 CFR Part 50)

10 CFR Part 50, Appendix A, General Design Criteria for Nuclear Power Plants (2/4/72)

8.1.4.2 Nuclear Regulatory Commission

1. NRC Regulatory Guide 1.6, Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems (3/10/71)

2. NRC Regulatory Guide 1.9, Selection of Diesel Generator Set Capacity for Standby Power Supplies (3/10/71)

3. NRC Regulatory Guide 1.22, Periodic Testing of Protection System Actuation Functions (2/17/72)

4. NRC Regulatory Guide 1.29, Seismic Design Classification (Revision 2, 2/76)

5. NRC Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (8/11/72)

6. NRC Regulatory Guide 1.32, Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants (Revision 2, 2/77)

7. NRC Regulatory Guide 1.41, Preoperational Testing of Redundant On-Site Electric Power Systems to Verify Proper Load Group Assignments (3/16/73)

8. NRC Regulatory Guide 1.47, Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems (5/73)

9. NRC Regulatory Guide 1.53, Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems (6/73)

10. NRC Regulatory Guide 1.62, Manual Initiation of Protective Actions (10/73)

11. NRC Regulatory Guide 1.63, Electric Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants (Rev. 2, July 1978)

12. NRC Regulatory Guide 1.73, Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants (1/74)

13. NRC Regulatory Guide 1.75, Physical Independence of Electric Systems (Revision 1, 1/75)

14. NRC Regulatory Guide 1.81, Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants (Rev. 1, 1/75)

15. NRC Regulatory Guide 1.89, Qualification of Class 1E Equipment for Nuclear Power Plants (11/74)

16. NRC Regulatory Guide 1.93, Availability of Electric Power Sources (12/74)

17. NRC Regulatory Guide 1.106, Thermal Overload Protection for Electric Motors on Motor Operated Valves (Revision 1, March 1977)

18. NRC Regulatory Guide 1.108, Periodic Testing of Diesel Generator Units used as Onsite Electric Power Systems at Nuclear Power Plants (Revision 1, August 1977)

19. NRC Regulatory Guide 1.118, Periodic Testing of Electric Power and Protection Systems (June 1976)

20. NRC Regulatory Guide 1.129, Maintenance, Testing and Replacement of Large Lead Storage Batteries for Nuclear Power Plants (Revision 1, February 1978)

21. NRC Regulatory Guide 1.131, Qualification Tests of Electric Cables, Field Splices, and Connections for Light-Water-Cooled Nuclear Power Plants. 8/77 (for comments)

8.1.4.3 Institute of Electrical and Electronics Engineers (IEEE)

1. IEEE 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations (Revision 1)

2. IEEE 308-1974, Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations

3. IEEE 317-1976, Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations

4. IEEE 323-1974, Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations

5. IEEE 334-1974, Standard for Type Tests of Continuous Duty Class 1E Motors for Nuclear Power Generating Stations

6. IEEE 336-1971 (ANSI N45.2.4), Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

7. IEEE 338-1971, Trial-Use Criteria for Periodic Testing of Nuclear Power Generating Station Protection Systems

8. IEEE 344-1975, Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations

9. IEEE 352-1972, Trial-Use Guide General Principles for Reliability Analysis of Nuclear Power Generating Station Protection Systems

10. IEEE 379-1972, Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

11. IEEE 382-1972 (ANSI N41.6), Guide for Type Test of Class 1 Electric Valve Operators for Nuclear Power Generating Stations

12. IEEE 383-1974, Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations

13. IEEE 384-1974, Trial-Use Standard Criteria for Separation of Class 1E Equipment and Circuits

14. IEEE 387-1977, Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations

15. IEEE 420-1973, Trial-Use Guide for Class 1E Control Switchboards for Nuclear Power Generating Stations

16. IEEE 422-1973, Guide for the Design and Installation of Cable Systems in Power Generating Stations (Draft 3)

17. IEEE-450-1995, IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications

18. IEEE 494-1974, Standard Method for Identification of Documents Related to Class 1E Equipment and Systems for Nuclear Power Generating Stations

8.1.4.4 Insulated Cable Engineers Association (ICEA)

1. IPCEA P-46-426 (IEEE S-135), Power Cable Ampacities, Volume 1, Copper Conductors, and Volume 2, Aluminum Conductors, 1962

2. ICEA P-54-440 (NEMA WC-51-1975), Ampacities, Cables in Open-Top Cable Trays, Rev. 2, August, 1979

8.1.4.5 American National Standards Institute (ANSI)

1. ANSI C37, Power Switchgear

2. ANSI C57, Transformers, Regulators, and Reactors

8.1.4.6 National Electrical Manufacturers Association (NEMA)

1. NEMA SG 3-1971, Low Voltage Power Circuit Breakers (9/71)

2. NEMA ICS, Industrial Controls and Systems With Revision 6

3. NEMA SG 4-1968, A-C High-Voltage Circuit Breakers

4. NEMA SG 5-1971, Power Switchgear Assemblies (3/71)

5. NEMA SG 6-1966, Power Switching Equipment

6. NEMA TR1-1971, Transformers, Regulators, and Reactors

7. NEMA MG 1-1972, Motors and Generators

8. NEMA VE 1-1971, Cable Tray Systems

9. NEMA AB 1-1975, Molded Case Circuit Breakers

10. NEMA FU 1-1972, Low-Voltage Cartridge Fuses

11. NEMA PB 1-1971, Panelboards With Revision 1

12. NEMA PB 2-1972, Dead-Front Distribution Switchboards With Revision 1

8.1.4.7 National Fire Protection Association (NFPA)

No. 70-1971, National Electrical Code

8.1.4.8 Underwriters' Laboratories, Inc. (UL)

1. UL-50, Electrical Cabinets and Boxes (1975)

2. UL-67, Electric Panelboards (Revision, 10/75)

3. UL-891, Dead-Front Electrical Switchboards (1975)

8.1.4.9 Illuminating Engineering Society (IES)

IES Lighting Handbook, Application Volume, 1981

8.1.5 COMPLIANCE WITH NRC REGULATORY GUIDES AND IEEE STANDARDS

The extent to which the recommendations of the NRC regulatory guides and IEEE standards are complied with is described in the following sections:

8.1.5.1 NRC Regulatory Guides

For description of compliance to the Regulatory Guides, see Appendix 1A(B) and 1A(N).

8.1.5.2 IEEE Standards

1. IEEE 338-1971, Trial-Use Criteria for Periodic Testing of Nuclear Power Generating Station Protection Systems

   Periodic testing of protection systems conforms to the requirements of this standard.

2. IEEE 344-1975, Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations

   All seismic Category I Class 1E equipment is seismically qualified in accordance with this standard.

   For details, see Sections 3.10B and 3.10N.

3. IEEE 387-1977, Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Generating Stations

The design criteria and the qualification and testing requirements of the diesel generator units conform to the requirements of this standard.

4. IEEE 420-1973, Trial-Use Guide for Class 1E Control Switchboards for Nuclear Power Generating Station.

   All Class 1E control boards are designed in accordance with IEEE 420-1973 requirements with following clarification:

   Lens and Buttons for approximately forty (40) safety system inoperable indication lights and for sixteen (16) non-safety valve control devices are constructed of “LEXAN” (poly carbonate) and “CELON” respectively. These indicating lights/buttons are grouped and enclosed in a metal housing to provide separation between them and other equipment on the main control board. The housings are flush mounted on the front of the main control board. Cable connectors are provided on the back plate of the housing for external wiring. Internal fire (unlikely event) in the housing will not significantly degrade the integrity of the main control board.

   Wire splices are used in limited applications on field cables that terminate in certain Class 1E panels, cabinets or racks. The normal design is to terminate field cables without the use of wire splices. The wire splices are only used where additional length is required for the field wire and it was not judged reasonable to pull a new field cable. The use of such wire splices has been minimized.

   The wire splices are butt splices. The crimping technique, device and materials used for the splices are identical to those used for the terminal lugs in that panel. The wire splices are only allowed on low power applications such as control cables. The inspection procedure verifies the operability of the spliced circuit by completion of a continuity check. The wire splices used are qualified for anticipated service conditions, and the splices are staggered or separated within the panel so that they are not adjacent to each other or pressing against one another in the same wire bundle. Since previously accepted crimping methods and materials are used, the splices are limited to low power circuits and to field cables that already terminate in the panel, and the required wire separation and wire bundle support is maintained, the wire splices are not expected to significantly alter the heat load in the panel, the probability of a fire or the operability of any equipment or cables in that panel.

5. IEEE 494-1974, Standard Method for Identification of Documents Related to Class 1E Equipment for Nuclear Power Generating Stations.

   All station design documents and drawings containing Class 1E equipment and systems, in whole or in part, are identified with the term “Nuclear Safety Related” in accordance with this standard or, as an alternative, with the equivalent term “CLASS I”. Vendor supplied documents and drawings are used in conjunction with station design documents and/or drawings which are properly identified as to their safety classification; therefore, vendor supplied documents and drawings are not necessarily identified as “nuclear safety related” in accordance with IEEE 494-1974.

TABLE 8.1-1
SAFETY LOADS AND FUNCTION

(Sheet 1 of 2)

Safety Load	Function	Power
Safety injection pumps	Provide emergency core cooling	AC
Charging pumps	Provide emergency core cooling	AC
Residual heat removal (RHR) pumps	Provide emergency core cooling and reactor heat removal during refueling operations	AC
Containment spray pumps	Provide cooling spray in containment following a loss-of-coolant accident (LOCA)	AC
Service water pumps	Provide cooling water for Component Cooling Water System (CCWS) heat exchangers, and emergency diesel generators	AC
Component cooling water pumps	Provide cooling water to safety-related equipment	AC
Auxiliary feedwater pumps	Provide adequate water to steam generators in the event of a unit trip coupled with a loss of offsite power	AC
Spent-fuel pool cooling and cleanup pumps	Cool spent fuel pool water	AC
Control Room emergency	Maintain safe environmental conditions for operating personnel air cooling units and limit ambient air temperature in safety-related compartments heating, ventilating, and air conditioning.	AC
Heating, ventilating,and air-conditioning (HVAC) water chiller	Provide cooling fluid for emergency air cooling units	AC
Motor-operated valves small motors, fans and heaters, associated with Safety-related equipment	Insure coordinated operation of safety-related systems	AC

TABLE 8.1-1
SAFETY LOADS AND FUNCTION

(Sheet 2 of 2)

Safety Load	Function	Power
Reactor Protection System and Engineered Safety Features (ESF) Actuation System	Provide safe plant shutdown	AC and DC
Plant instrumentation	Provide safe reactor operation	AC
Instrument buses	Provide power to instrumentation and control equipment	AC
Shutdown control and instrumentation	Provide control to shutdown plant from outside of Control Room.	AC and DC
Instrument bus inverters	Provide power to instrument buses	DC

8.2 OFFSITE POWER SYSTEM

8.2.1 DESCRIPTION

TO's transmission system serves as the main outlet and source of offsite power for the CPNPP. Connection of the station outputs to the system is achieved via 345-kV overhead lines to the 345-kV switchyard. Separate connections to the 138-kV switchyard and the 345-kV switchyard provide independent and reliable offsite power sources to the Class 1E systems of each unit.

Because the 345-kV system forms the backbone of the TO transmission system, it provides a highly reliable source of continuous power for plant shutdown. Another reliable source is the 138-kV network.

The TDSP's high-voltage (HV) switchyards at CPNPP consist of 345-kV switching facilities and 138-kV switching facilities and are an integral part of the TO transmission system. The network interconnections to CPNPP switchyards are made through seven 345-kV and two 138-kV transmission lines to other switching stations within the TO transmission system as shown on Figure 8.2-4. There are no interconnections between the 138-kV switchyard and the 345-kV switchyard at the CPNPP site. The 138-kV switchyard is physically and electrically independent of the 345-kV switchyard.

Essentially, the 345-kV and the 138-kV switchyards each consist of a two-bus arrangement having one breaker per transmission circuit. Transmission circuits terminate in individual positions on alternate buses in the switchyards. Power can be supplied to each switchyard from any of their respective transmission circuits.

The CPNPP switchyards are located approximately 600 ft due west of the Turbine Building. Figure 8.2-1 shows the physical orientation and separation of the high-voltage switchyards, main, station service and startup transformers, and transmission lines routing from the transformers, and transmission lines routing from the transformers to the switchyards. The CPNPP HV switchyards' configurations are shown on Figure 8.2-4.

Two three-phase, half-size, step-up transformers are provided for each unit to raise the 22-kV generator voltage to 345-kV prior to transmission via overhead lines to the CPNPP 345-kV switchyard. Each CPNPP unit output line is connected to both 345-kV buses through two breakers which function as generator circuit breakers. The units are synchronized to the system across the generator circuit breakers. In the event of a unit trip, these breakers isolate the associated generator from the system. If required, the generators can be isolated individually by removing the bus links in the main isolated-phase bus, permitting energization of the non-safety-related 6900-V auxiliary bus system by closing the generator circuit breakers and backfeeding through the main and unit auxiliary transformers.

The CPNPP offsite power source line for start up transformer XST1 is connected to both 138-kV buses thru two breakers which function as a bus tie. The offsite power source line for start up transformer XST2 is connected to both 345-kV buses thru two breakers which function as a bus tie.

Startup transformer XST1 and alternate startup transformer XST1A are connected to a common overhead line from the 138-kV switchyard. Each transformer is provided with a 138-kV motor-

operated air switch such that each transformer can be energized independent of the other transformer.

Startup transformer XST2, alternate startup transformer XST2A and station service transformer 1ST are connected to a common overhead line from the 345-kV switchyard. Each transformer is provided with a 345-kV motor-operated air switch such that each transformer can be energized independent of the other transformer.

Alternate startup transformer XST1A is located under the 138-kV line to XST1 (refer to Figure 8.2-1) to serve as a replacement of XST1 after a future plant modification to connect cable buses from secondary X and Y windings of XST1 and XST1A to tranfer panels to provide 138-kV offsite power to Units 1 and 2 safety related buses.

Alternate startup transformer, XST2A with dual primary windings (345-kV and 138-kV), is in a location under the 345-kV line to XST2 (refer to Figure 8.2-1) to serve as a replacement of XST2. Cable buses from secondary X and Y windings of XST2 and XTS2A are connected to two 6.9kV transfer panels to provide 345kV offsite power to Units 1 and 2 safety related buses. These transfer panels allow transfer of 345kV offsite power source for safety related buses from XST2 to XST2A and vice verse.

Station service transformer 2ST is connected to the 345-kV switchyard west bus via a dedicated circuit breaker and overhead line.

The 138-kV and 345-kV circuit breakers are provided with an energy storage mechanism that allows the operation of the individual circuit breaker without having an external source of power. The circuit breakers have two separate avenues of relay protection termed primary and secondary or backup to provide a high degree of operational reliability.

The 125-VDC supply, for each of the switchyard relays, is segregated into two completely independent systems, one for the primary relays and the other for the backup relays. These two systems are independent of both the station DC systems and the DC systems of the other switchyard.

The 345-kV switchyard TO circuit breakers may be operated from either the 345-kV Switchyard Control Building or remotely from Oncor's System Operations Center. Control of CPNPP 345-kV switchyard circuit breakers and motor-operated air switches is administered from the plant Control Room except for the motor-operated air switch for transformer XST2A, which has local motor control. The 138-kV switchyard circuit breakers may be operated from either the 138-kV Switchyard Relay House or remotely from TO's System Operations Center. The 138-kV motor-operated air switch (DXST1) may be operated from the Control Room. The 125-VDC control power for circuit breakers and motor-operated air switches in the 345-kV system is independent of the 125-VDC control power for circuit breakers and motor-operated air switches in the 138-kV system.

Physical layouts of the switchyards are shown in Figures 8.2-5 and 8.2-7.

The substations that are connected to the CPNPP switchyards (as shown on Figure 8.2-4) are as follows:

- DeCordova (138-kV)

- Stephenville (138-kV)
- DeCordova (345-kV)
- Wolf Hollow (345-kV)
- Everman (345-kV)
- Johnson Switch (345-kV)
- Comanche Switch (345-kV)
- Parker No. 1 (345-kV)
- Parker No. 2 (345-kV)

The layout of transmission lines from TO's CPNPP switchyards to other switching stations, in the vicinity of CPNPP switchyards is shown in Figure 8.2-12.

The following combinations of lines form double-circuits routed on common transmission towers:

345-kV Parker No. 1 and 345-kV Parker No. 2

345-kV Comanche Switch and 138-kV Stephenville

345-kV Everman and 345-kV Johnson Switch

345-kV DeCordova and 345-kV Wolf Hollow

The 138-kV line to DeCordova is supported by independent transmission towers and shares the same right-of-way as the Wolf Hollow and DeCordova 345-kV circuits (Figure 8.2-12). Routing of this circuit was selected to avoid crossings with the 345-kV overhead lines, thereby maintaining a high degree of circuit reliability and availability (Figures 8.2-1 and 8.2-12).

The 138-kV line to Stephenville passes beneath the 345-kV lines to DeCordova, Wolf Hollow, Everman, and Johnson Switch. The minimum overhead clearance between the Stephenville line and the 345-kV lines is 20 ft.

In addition to the transmission line circuit breakers in the 138-kV switchyard, there are two Plant Support Power System transformers. These fully redundant transformers provide a reliable source of power to plant support loads.

Two physically independent and redundant sources of offsite power are available on an immediate basis for the safe shutdown of either unit. The preferred source to Unit 1 is the 345-kV offsite supply from the 345-kV switchyard and the startup transformer, XST2; the preferred source to Unit 2 is the 138-kV offsite supply from the 138-kV switchyard and the startup transformer, XST1. Each of the startup transformers (XST1 and XST2) normally energizes its related Class 1E buses; i.e., XST1 normally energizes Unit 2 Class 1E buses and XST2 normally energizes Unit 1 Class 1E buses. This eliminates the need for automatic transfer of safety-related loads in the event of unit trips. In the event one startup transformer (e.g., XST1, a

preferred source) becomes unavailable to its normally fed class 1E buses, power is made available from the other startup transformer (e.g., XST2, an alternate source) by an automatic transfer scheme, described in Section 8.3.1.1.5. This limits plant transients due to loss of a preferred source to only one unit. Capability is provided to test the transfer scheme, during power operation, by manually causing loss of voltage to the undervoltage relays which results in tripping the appropriate startup transformer breaker in the 6.9-kV safety related switchgear. Periodic testing of the automatic transfer scheme is performed as specified in the Technical Specifications.

Additionally, two station service transformers are provided for the non-safety-related auxiliaries, one for each unit. The source for these non-safety-related buses is the 345-kV offsite power supply from the switchyard and transformers 1ST (Unit 1) and 2ST (Unit 2).

The two startup transformers which feed the emergency buses (XST1 and XST2) are connected to the safety-related 6900-V auxiliary bus systems by separate, metal-enclosed, ventilated, louvered top cover, cable bus ducts and short sections of ventilated, solid top cover, cable tray. Cable spacing is maintained within each bus duct and cable tray. Figure 8.2-11 shows the layout and connections of the cable bus ducts/cable trays.

The preferred and alternate power source bus ducts and cable trays for each unit, where routed in the same area, are in areas which are free of hazards from rotating equipment.

For fires that affect both preferred and alternate power source bus ducts, the CPNPP fire protection program has provided adequate protection to ensure safe shutdown can be achieved. For other single external events, the bus duct and cable tray construction, separation and independence provided between the preferred and alternate power source bus ducts assure that simultaneous failure of both bus ducts/cable trays will not occur. For example, separate independent circuits are provided for the bus duct connections to the onsite distribution systems. The possibility of a single external fire near the west wall of the Auxiliary Building causing damage to bus ducts A2, B1 and B2, is minimized by the inaccessible location of the subject ducts (see Figure 8.2-11), and the following features:

1. There are no fixed external ignition sources located in this area;

2. Inaccessibility to the area restricts the introduction of transient combustible materials;

3. Thermal type fire detectors and a fixed wet pipe sprinkler system are provided in this area (refer to the CPNPP Fire Protection Report);

4. Bus duct enclosures consist of totally enclosed ventilated metal type construction;

5. Bus duct cables meet the flame test requirements of IEEE 383-1974; and,

6. Bus ducts and cable trays are separated from the rooms below by a concrete fire barrier roof.

The Fire Detection System and the protection of the preferred offsite power system is described in Section 9.5.1.

8.2.1.1 Design Basis

ERCOT requires the TO to uphold Generators (CPNPP) Federal (NRC) licensing requirements. TO has implemented CPNPP specific guidelines in their Transmission Planning and CPNPP Switchyards Working Procedures to assure adequacy of CPNPP offsite power sources.

The ERCOT requirements to uphold CPNPP licensing requirements and the implementation of the CPNPP specific requirements by TO enhances the reliability and availability of CPNPP offsite sources. The offsite power systems are capable of providing reliable sources of power to the Class 1E systems of each unit in compliance with NRC General Design Criterion (GDC) 17, NRC Regulatory Guide 1.32 [3], and IEEE 308 [6]. Design of the offsite power systems for CPNPP exceeds the minimum requirements cited in these regulations.

8.2.1.2 Compliance with Standards

8.2.1.2.1 Compliance with General Design Criteria 17

Two independent power sources are available on an immediate basis following a DBA to ensure operation of the vital safety functions. Because the Class 1E buses of each unit are normally energized from the preferred offsite power source (see Section 8.3), switching is not required to make this source available. The second offsite source (alternate) is available within seconds. These two sources of power exceed the minimum requirements of GDC 17 which stipulate that one circuit shall be available within seconds.

Physical separation and independence of the transformers and transmission lines minimize the likelihood of their simultaneous failure. A layout presenting the arrangement and separation of the transformer and transmission lines is shown on Figure 8.2-1. The electrical outputs from Units 1 and 2 are connected to separate positions located at opposite ends of the switchyard. These unit output lines and the 345-kV offsite power source to the Class 1E systems are arranged with adequate separation to preclude failure of either output line which would create a failure on the 345-kV offsite power circuit. There are no transmission line crossings from the switchyard to the plant.

Disruption of both offsite power sources resulting from multiple equipment failures caused by tornadoes, ice storms, thunderstorms, or large missiles is considered highly improbable.

The overhead line design meets the requirements of the National Electrical Safety Code [8] for heavy loading district, Grade B construction, and is based on a lightning performance of less than one outage per 100 miles per year. The transmission lines have two overhead ground wires for protection from lightning. Design of switchyard components is in accordance with IEEE, ANSI, and NEMA standards.

8.2.1.2.2 Compliance with General Design Criteria 18

The offsite power system circuitry is designed to permit periodic testing of operability and functional performance of power supplies, relays, and switches.

Under conditions as close to design as practical, testing the operational sequence that brings the system into operation and transfer of power between the preferred and standby power sources is performed during the refueling shutdown.

8.2.1.2.3 Compliance with IEEE 308 and NRC Regulatory Guide 1.32

The offsite power systems described previously exceed the minimum requirements of IEEE 308, which stipulates that each safety load group has access to a preferred power supply consisting of one or more power sources. Furthermore, the design conforms to the preferred design outlined in NRC Regulatory Guide 1.32, i.e., inclusion of two immediate access circuits from the transmission network.

Considerations for multi-unit stations given in IEEE 308 permit sharing of the preferred power supply between units as long as sufficient capacity is provided to carry the Engineered Safety Features (ESF) for a Design Basis Accident (DBA) on one unit and on those systems required for a concurrent safe shutdown on the second unit. The preferred offsite power systems for CPNPP are supplied through two startup transformers common to both units. These transformers have more than ample capacity to operate the ESF loads for DBAs on both units simultaneously, although the design criteria requires consideration of a DBA on one unit only.

8.2.1.2.4 Compliance with NRC Regulatory Guide 1.93

As described in the Technical Specifications, power operation is initiated and continued without restriction only when the Limiting Conditions for Operation (LCO) are met. If the LCO is not met, power operation is restricted, as explained in the Technical Specification.

8.2.1.2.5 Compliance with IEEE 336 (7) and NRC Regulatory Guide 1.30 (2)

The Quality Assurance Program for the Class 1E portions of the CPNPP preferred power system is based on the requirements of IEEE 336 and Regulatory Guide 1.30. For details see Chapter 17 and Appendix 1A(B).

8.2.1.2.6 Compliance with NRC Regulatory Guide 1.47

The surveillance of the off-site preferred power system operability status is based on the requirements of Regulatory Guide 1.47 augmented by Branch Technical Position ICSB 21 as described herein:

A system level indication is provided to indicate if a preferred power source is unavailable. This indication for Train A Unit 1 is activated on:

1. Loss of preferred source voltage

2. Breaker 1EA1-1 control switch in the pull to lock position

3. Operator manual action

Train B is similar to Train A. A duplicate scheme is provided for Unit 2.

8.2.2 ANALYSIS

Offsite power sources are not obtained from a common switchyard. The 138-kV switchyard is physically separated from the 345-kV switchyard. There is no interconnection between the CPNPP 345-kV and 138-kV switchyards. (See Figure 8.2-1). The control supply of the 138-kV

circuit breakers is independent of the control supply of the 345-kV circuit breakers. The source of DC power provided for the 138-kV switchyard is separate from the source of DC power for the 345-kV switchyard. See description in 8.2.1. The offsite power source lines from 138-kV and 345-kV switchyards to startup transformers XST1 and XST2 do not cross each other or any other transmission line from the switchyards to the plant. The power from 138-kV and 345-kV switchyard buses, through startup transformers XST1 and XST2, to Safety related buses constitute the offsite power sources for CPNPP.

The 345-kV transmission lines (Parker No. 1 and Parker No. 2 double-circuit line, Everman and Johnson Switch double-circuit line, Comanche Switch line, and the Wolf Hollow and DeCordova double-circuit line), which connect to the CPNPP 345-kV switchyard, are also physically separated from one another. The transmission lines, which emanate from the CPNPP switchyards, do not cross each other, with the exception of the Stephenville 138-kV line, which crosses underneath the Wolf Hollow and DeCordova double circuit and Everman and Johnson Switch double-circuit 345-kV lines. Failure of a tower carrying the Comanche Switch and Stephenville lines would not impact the continued availability of either offsite source. Similarly, failure of a tower carrying the Wolf Hollow and DeCordova double-circuit or Everman and Johnson Switch double-circuit lines would not impact the continued availability of either offsite source. The failure of a tower carrying the Parker No. 1 and Parker No. 2 double-circuit line would not impact the continued availability of either offsite source. The failure of a tower carrying the 138-kV Decordova line would not impact the continued availability of 345-kV offsite source; however, it may impact the immediate availability of 138-kV offsite source. The physical separation of switchyards, primary and backup protection systems, and the stable transmission grid system minimizes the probability of simultaneous failures of offsite power sources.

The bulk transmission system of the ERCOT and the TO transmission system are designed to withstand the loss of the largest power plant and to retain the integrity of the remaining bulk transmission system.

The full load capacity of CPNPP at the time of Unit 1 installation represented two to three percent of the ERCOT estimated peak load and, with the addition of the second unit, was equivalent to approximately five to six percent of the estimated peak. Actual disturbances on the ERCOT system have occurred where large amounts of capacity were lost, one as high as 10 percent, with no integrity degradation of the transmission system observed.

Studies confirm that loss of the CPNPP plant when 100-percent loaded will not impair the integrity of the bulk transmission system for conditions representative of those projected at the time of installation of Unit 1 or both Units 1 and 2.

The stability studies demonstrate both the effect on the transmission system when one or both of the CPNPP units are lost and when the plant auxiliaries are transferred to the standby source. It is evident from the studies that loss of one or both of the nuclear units will not cause the loss of auxiliary power to the station. In addition, the system remains stable for all disturbances near CPNPP which are cleared by primary or backup relaying.

Simultaneous loss of either unit and the most critical Generator does not affect the capability of either offsite source to furnish shutdown power on an uninterrupted basis.

Simultaneous loss of either unit and the most critical transmission line does not adversely affect the capability of the system to furnish shutdown power on an uninterrupted basis. The steady-state and transient stability analyses are described in Reference [9].

The normal operating voltages at CPNPP for the 345-kV and 138-kV (nominal) offsite power grid are approximately 354-kV and 142-kV. These normal operating voltages are subject to periodic review and adjustment based on the requirements of the TO system which may change during the operating life of CPNPP.

The maximum voltages at CPNPP are 361-kV and 144-kV. These maximum grid voltages are based on equipment ratings (circuit breakers, transformers, etc.) and are controlled by generator excitation (throughout the grid), and switching of shunt reactors and capacitors. The minimum voltage for the respective grids at CPNPP has been calculated to be 340-kV and 135-kV for normal and credible contingency conditions respective to CPNPP.

On the basis of these voltage ranges of 340-kV to 361-kV and 135-kV to 144-kV for the offsite power sources, class 1E bus voltage ranges are determined to be within the out-of- tolerance voltage values of Table 8.3-1C. All class 1E equipment can operate continuously at these voltages for all modes of plant operation to perform their safety function.

Grid voltages lower than those calculated could occur for situations involving contingencies in the grid system. Periodically, such situations are studied. These studies are conducted in accordance with the ERCOT Planning Criteria and the TO Transmission Planning Procedures. See Section 8.3.1.1.5 for discussion of the automatic transfers which occur for condition of undervoltage.

The nominal frequency on the ERCOT system is 60 ± .03 hz. On occasion when large amounts of generation are lost, the frequency will drop to 59.6 hz and recover within a few seconds to 59.8 hz and within a few minutes to normal, 60.0 hz. The deviations in frequency are well within the operating ranges of the Class 1E equipment.

Studies have been and are continually being made where catastrophic disturbances are postulated to test the ERCOT system against events beyond the design criteria. The lowest frequency observed on these studies has been 57.5 hz, for which the system recovered with no cascading shutdowns.

The frequency decay rates observed on the ERCOT system during daily operation are usually less than 1.5 hz/sec. Location or origin of disturbance should have little effect on frequency decay rate. The type of system disturbance postulated in the above studies resulted in a maximum calculated frequency decay rate of 2.4 hz/sec.

One inconceivable situation has been studied to determine a maximum frequency decay rate at Comanche Peak which resulted in a calculated decay rate of 4.37 hz/sec. This situation envisioned the total Dallas/Fort Worth metro area load being dumped on the Comanche Peak unit instantaneously and all other sources of generation removed.

In order to satisfy offsite power requirements, the TO should maintain 345kV grid system voltage at CPNPP switchyard between the voltage range of 340kV to 361kV and 138-kV grid system voltage at CPNPP switchyard between the voltage range of 135-kV to 144-kV.

Grid configuration and reliable operation is maintained through tested and proven operating procedures and guidelines. TO is a member of ERCOT which continually plans (coordinates) the capacity on line (to serve load), the amount of responsive reserve, the maintenance of units, the maintenance of grid components, and the scheduled transfer of energy between members. Many entities in ERCOT have their own control centers where the systems are monitored. Parameters monitored in these control centers are: system frequency, grid voltages (at many points on system), generation (all units), transmission line flows, and reserve capacity. Through use of these tools and adherence to operating guides, experience has proven grid integrity over a long period of time.

The responsive reserve on the ERCOT system is coordinated by the ERCOT. ERCOT maintains a minimum responsive reserve of 2300 MW. The amount of responsive reserve is subject to periodic review and adjustment based on the requirements of ERCOT, which may change during the operating life of CPNPP. This reserve is shared among all operating plants and loads acting as resources (interruptible loads) throughout the system and not concentrated in specific areas or any particular plant. No restrictions are placed on specific responsive reserve in relation to Comanche Peak.

The operators at the Comanche Peak plant have available to them in the control room:

1. Grid frequency,

2. 345-kV and 138-kV Comanche Peak bus voltages, and

3. Constant communication (dedicated circuits) with TO System Operation Center.

Loss of the Comanche Peak unit or largest system load should not adversely affect shutdown power because of logical reasons:

1. Loss of further generation during lower than normal frequency would result in automatic shedding of load which acts to restore frequency,

2. When the system loses load during low frequency or low voltage conditions, the system automatically moves toward a more nearly normal condition, and

3. If the system voltage drops below the minimum calculated values described above and causes the voltages at the plant switchgear buses to drop below the degraded voltage protection settings, the plant would be isolated from the offsite power sources and the standby diesels would automatically start to ensure a source of shutdown power.

REFERENCES

1. 10 CFR Part 50, General Design Criteria for Nuclear Power Plant Construction Permits, U.S. Nuclear Regulatory Commission (2/4/72).

2. NRC Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment, August 11, 1972, U. S. Nuclear Regulatory Commission.

3. NRC Regulatory Guide 1.32, Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants (Revision 2, 2/77).

4. NRC Regulatory Guide 1.47, Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems, May 1973, U.S. Nuclear Regulatory Commission.

5. NRC Regulatory Guide 1.93, Availability of Electric Power Sources, December 1974, U.S. Nuclear Regulatory Commission.

6. IEEE 308-1974, Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations.

7. IEEE 336-1971 (ANSI N45.2.4-1972), Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations.

8. National Bureau of Standards of U.S. Department of Commerce, National Electrical Safety Code, Handbook 81 (ANSI C2.2-1960) 6th ed.

9. 1980-1982 Texas Utilities Company System Comanche Peak Stability Study.

10. M. M. Merrian and P. J. VandeWalle, 1976, The Effect of Grid Frequence Decay Transients on Pressurized Water Reactors, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-95, No. 1, p. 269.

11. 1980/81-1982/83 Winter Peak TUCS Supplemental Comanche Peak Report, April 9, 1974.

TABLE 8.2-1
THIS TABLE IS DELETED.

8.3 ONSITE POWER SYSTEMS

8.3.1 AC POWER SYSTEMS

The onsite AC Power Systems consist of various auxiliary electrical systems designed to provide reliable electrical power to Class 1E and non-Class 1E station loads. (See Figure 8.3-1.) The AC Essential Lighting System connected to Class 1E power buses is described in Section 9.5.3.

Redundancy of Class 1E onsite AC Power Systems ensures safe reactor shutdown during a Safe Shutdown Earthquake (SSE) or DBA coincident with any single failure within the standby AC Power System or the 118-V uninterruptible AC Power System.

The standby AC Power System ensures safe plant shutdown when the preferred and alternate offsite power sources are not available. The 118-V uninterruptible AC Power supply feeds power to reactor protection instrumentation and control systems and to other Class 1E components and systems essential to safe reactor operation.

8.3.1.1 Description

8.3.1.1.1 System Structure (Network)

Any one of the following systems can furnish power to the Class 1E onsite AC power distribution systems:

1. Preferred power system (offsite power sources, 345-kV source for Unit 1 and 138-kV source for Unit 2)

2. Alternate power system (alternate offsite power source, 138-kV source for Unit 1 and 345-kV source for Unit 2)

3. Standby power system (diesel generators)

   CPNPP has also provided a set of non-safety related Alternate Power Diesel Generators (APDGs) for each unit with the capability to connect to a Class 1E train at a time to provide defense-in-depth for safe shutdown of a unit during outages or during extended duration of an inoperable offsite circuit on occurrence of concurrent loss of offsite power and failure of EDGs. The APDGs may provide 3450 kVA to provide long term cooling of each unit. See Subsection 8.3.1.2.1.7.h for a discussion of the sizing of APDG cables.

Additionally, the system structure during unit startup is described in item 4.

These systems perform as described in the following paragraphs:

1. Preferred Power System

   The preferred power sources supply power to the Class 1E buses during plant startup, normal operation, emergency shutdown, and upon a unit trip. These sources originate as part of the 138-kV and 345-kV offsite power systems (discussed in Section 8.2) and supply power to the 6900-V Class 1E auxiliary bus systems through two startup transformers; these are designated XST1 and XST2 on Figure 8.3-1.

Each startup transformer is rated 35/46.7/58.3 MVA, three phase, 60 Hz; each has two secondary windings, x and y, each rated 17.5/23.3/29.2 MVA, three phase, 60 Hz. The secondary windings are connected to the 6900-V Class 1E buses as described below and in Subsection 8.3.1.1.2.

Transformer XST1 is connected to the 138-kV Switchyard via an overhead transmission line as shown on Figure 8.2-2. The secondary connections at 6900-V are made as follows: the x-winding is connected to Class 1E buses 1EA1 and 1EA2 of Unit 1, and the y-winding is connected to Class 1E buses 2EA1 and 2EA2 of Unit 2. Startup transformer XST1 serves as the preferred power source to Unit 2 Class 1E buses 2EA1 and 2EA2 and as the alternate power source to Unit 1 Class 1E buses 1EA1 and 1EA2 as shown on Figure 8.3-1.

The second offsite power source is provided through 345-kV transformer XST2. The transformer primary is connected to the 345-kV Switchyard, located approximately 600 ft away, via an overhead transmission line. This connection is shown on Figure 8.2-2. The switchyard offers a highly reliable source of power because it can be supplied by seven separate transmission lines from various switching stations on the TO system in conjunction with the two CPNPP unit outputs (discussed in Section 8.2).

The secondary connections at 6900-V are made as follows: the x-winding is connected to Unit 2 Class 1E buses 2EA1 and 2EA2, and the y-winding is connected to Class 1E buses 1EA1 and 1EA2 of Unit 1. Startup transformer XST2 serves as the preferred power source to Unit 1 Class 1E buses 1EA1 and 1EA2 and as the alternate power source to Unit 2 Class 1E buses 2EA1 and 2EA2 as shown on Figure 8.3-1.

2. Alternate Power System

As described previously, startup transformer XST1 serves as an alternate source of offsite power to Unit 1 Class 1E buses 1EA1 and 1EA2 as shown on Figure 8.3-1.

Startup transformer XST2 serves as an alternate source of offsite power to the Unit 2 Class 1E buses 2EA1 and 2EA2 as shown on Figure 8.3-1.

Each startup transformer has the capacity to carry the required Class 1E loads of both units during all modes of plant operation.

In determining the capacity of 138-kV startup transformer XST1, the following abnormal conditions were considered to occur simultaneously, and represent the worst case loading condition.

a. Preferred (345-kV) off site power supply to Unit 1 safeguards buses is unavailable and these buses are powered from the 138-kV source.

b. Unit 1 trips at full power.

c. DBA occurs on Unit 2.

The above conditions result in the 138-kV startup transformer (XST1) carrying the required safeguards load of Unit 1 and Unit 2.

The above conditions apply equally to the 345-kV startup transformer when considering loss of the 138-kV startup transformer, a DBA on Unit 1 and a Unit 2 trip from full power.

Under DBA conditions, the safety loads are always started in sequence via the safeguards sequencer as discussed in Section 8.3.1.1.5.

Therefore, the Class 1E buses of each unit can be supplied by two independent and reliable immediate-access offsite power sources. Sharing of these offsite power sources between the two units has no effect on the station electrical system reliability because each transformer is capable of supplying the required safety-related loads of both units if it becomes necessary to safely shut down both units simultaneously.

3. Standby Power System (Diesel Generator)

The standby AC Power System is an independent, onsite, automatically starting system designed to furnish reliable and adequate power for Class 1E loads to ensure safe plant shutdown and standby when preferred and alternate power sources are not available. Electrical equipment associated with starting of the diesel generators are enclosed in cabinets and appropriate procedures are in place to ensure the proper degree of cleanliness is maintained on a plant wide basis commensurate with the design and operating requirements of the equipment, in order to minimize diesel generator failure due to accumulation of dust or other particles on these equipment. Four independent diesel generator sets, two per unit, are provided. The manufacturer/model number for the diesel engine is Delaval/DSRV-16-4; the manufacturer/model number for the generator is EP Portec/L-11091.

Each generator is driven by a single prime mover and is capable of sequentially starting and supplying the minimum power requirements for a DBA or blackout in one unit. The four diesel generators are electrically and physically independent. They are located above the water level of the probable maximum flood (PMF) level (789.7 ft). Each diesel generator and its associated equipment is located in a separate room with walls designed to protect the diesel generators and associated equipment against an SSE, tornadoes, missiles, and fire. See Figures 1.2-11 and 1.2-17.

4. Unit Startup

Startup of Unit 1 is accomplished using non-Class 1E buses 1A1, 1A2, 1A3, and 1A4 which are supplied from 345-kV station service transformer 1ST and Class 1E buses 1EA1 and 1EA2 from 345-kV startup transformer XST2. Following the main generator synchronization to the system, the aforementioned non-Class 1E buses are transferred live to unit auxiliary transformer 1UT.

For startup of Unit 2, non-Class 1E buses 2A1, 2A2, 2A3, and 2A4 are supplied from 345-kV station service transformer 2ST, and Class 1E buses 2EA1 and 2EA2 from 138-kV startup transformer XST1. Following the main generator synchronization to the system, the non-Class 1E buses are transferred live to unit auxiliary transformer 2UT.

Bus XA1 can be powered from either 345-kV station service transformer 1ST or 2ST.

5. Plant Support Power System

The 25 KV Plant Support Power Loop, feeding certain non-safety-related equipment, is supplied from two Plant Support Power System transformers located in the 138 KV switchyard. The system can also provide power, via manual transfer switches (inside key-locked enclosures), to certain safety-related equipment during bus outages in plant Modes 5 and 6.

8.3.1.1.2 Busing Arrangement, Interconnections, and Load Assignment

Two independent and redundant 6900-V Class 1E buses are provided for each unit, each capable of supplying the required safety-related loads to safely shut down the unit following a DBA. Each Class 1E bus can be fed from two independent offsite power sources or the diesel generator assigned to the bus. Arrangement of buses is shown on Figure 8.3-1; assignment of emergency loads is indicated in Tables 8.3-8 and 8.3-9. Redundant safety-related loads are divided between Trains A and B so that loss of either train does not impair fulfillment of the minimum shutdown safety requirements. There are no manual or automatic connections between Class 1E buses and loads of redundant trains. Electrical separation of redundant trains is maintained through all voltage levels, including DC and instrumentation.

FSAR figures are based on Unit 1 and Common drawings and bus configurations. Unit 2 uses the same design criteria as Unit 1 and no Unit 2 specific FSAR figures are submitted. Unit 2 electric equipment have the same tag numbers as the Unit 1 electrical equipment shown on the figures in FSAR Section 8.3 except for the unit designator which is “2” versus “1”. Minor differences in regard to load bus assignment, cable numbers, compartment numbers and references exist between Unit 1 and Unit 2 are not reflected in these figures.

Safety-related (Class 1E) 6900-V buses 1EA1 and 1EA2 for Unit 1 and 2EA1 and 2EA2 for Unit 2 are fed directly from dedicated startup transformers XST1 and XST2. There are no interconnections between safety-related and non-safety-related 6900-V buses.

The reactor coolant pump motors are connected to the 6900-V non-Class 1E buses located in the non-seismic category area, as shown on Figures 1.2-25 and 1.2-30 and as discussed in Section 3.2. The reactor coolant pump motors are not Class 1E.

8.3.1.1.3 Redundant Bus Separation

All Class 1E buses are arranged in such a way that train A buses are electrically and physically isolated from train B buses to satisfy the single failure criteria. Physical locations of these buses are shown on Figures 1.2-11 and 1.2-13.

The redundant 6900-V and 480-V Class 1E switchgear assemblies are located in separate rooms in the seismic Category I Safeguards Buildings. Each room contains only electrical equipment, therefore minimizing exposure to mechanical, water, or fire damage caused by equipment such as steam lines, waterlines, pumps, and motors. Separation between train A and train B switchgear is accomplished by placing the equipment on two different floor elevations.

8.3.1.1.4 Equipment Capacities

All switchgear is adequately sized and coordinated to permit safe and reliable operation under normal and short-circuit conditions.

Interrupting ratings of Class 1E switchgear, motor control centers (MCCs), and distributions boards are as follows:

Equipment	Class	Interrupting Current
6.9-kV switchgear	7.2 kV	40,000 A at 7.2 kV
480-V switchgear	600 V	50,000 A at 480 V
480-V motor control centers	600 V	25,000 A at 480 V Exception: 24,000A at 480V for MCC XEB1-1, XEB1-2, XEB2-1, XEB2-2
208/120-VAC, 120-VAC, and 118-VAC distribution panels	277 V	10,000 A at 208 V
125-VDC Class 1E switchboards	250 V	20,000 A at 125 V
125-VDC Class 1E distribution panels	250 V	10,000 A at 125 V

The diesel generators are sized so that each set is capable of carrying the required load for one unit in the unlikely case of a DBA or blackout. Based on the demands given in Tables 8.3-1 and 8.3-2, the continuous output rating of each diesel generator is 7000 kW at 0.8 power factor, 6900 V, three phase, 60 Hz, and has a normal operating speed of 450 rpm. Each diesel generator has a two hr rating of 7700 kW. The diesel generator excitation characteristic curve is provided in Figure 8.3-19.

The design and continuous rating is consistent with NRC Regulatory Guide 1.9 and IEEE 387-1977 [32].

The capacities of individual loads are determined on the bases of nameplate rating, pump pressure and flow conditions, rated BHP, or pump runout conditions. Basis of selection is noted in Tables 8.3-1 and 8.3-2.

8.3.1.1.5 Automatic Transfers, Loading and Load Shedding

8.3.1.1.5.1 Non-Class 1E Bus - Automatic Transfer

When Unit 1 trips, the power source for Bus 1A1 is automatically transferred from main generator 1G to transformer 1ST.

The logic, and typical electric schematics for Bus 1A1 are shown in Figure 10.2-1. Depending on the system conditions, this automatic transfer will be either “fast” or “slow” as described below:

Energizing of relays 86-1/1G, 86-2/1G, 94-1B/1G and 94-2B/1G results in tripping of the main generator. Upon operation of any of these relays, the normally closed incoming breaker 1A1-1 receives a trip signal.

An “early 52-b” contact of this breaker will send a signal to automatically close the offsite source incoming breaker 1A1-2 by:

1. Fast transfer, provided the

   a. Offsite source voltage is available (this voltage is monitored by undervoltage relays 27/1ST set to drop out at approximately 85% of nominal system voltage of 6900 volts) and,

   b. Offsite source and the bus 1A1 voltages are not out of phase by more than 40 degrees (as seen by the synchronism check relay 25/1A1).

   c. This transfer is completed in the minimum time possible (maximum of 10 cycles), however, it is disabled after 15 cycles from initiation to eliminate the possibility of accidental closure in case of any contact malfunction in the close circuit.

A successful fast transfer assures maintenance of voltage on bus 1A1 without interruption.

2. Slow transfer, if the requirements of a. are not satisfied within approximately 15 cycles after the closure of the “early 52-b” contact of the normally closed incoming breaker, provided:

   a. Voltage on the bus (to be transferred) has decreased to approximately 30% of the nominal voltage of 6900 volts,

   b. Offsite source voltage is available as described in 1.a) and

   c. All motor feeder breakers on bus 1A1 have tripped as evidenced by closure of their “52-b” contacts. Tripping of these motor feeder breakers is accomplished by bus undervoltage relays set at approximately 30% of the nominal voltage of 6900 volts via timers set at approximately 0.5 seconds.

The main generator 1G tripping is delayed by 30 seconds subsequent to a reactor trip (see FSAR Figure 7.2-1 Sheet 16 and Figure 10.2.1). This ensures full coolant flow for 30 seconds after a reactor trip before any bus transfer is made.

The automatic transfers of the other non-Class 1E buses (1A2, 1A3, 1A4, 2A1, 2A2, 2A3, and 2A4) are the same as discussed for 1A1 above.

8.3.1.1.5.2 Class 1E Buses-Automatic Transfer

1. Undervoltage Sensors to detect loss of offsite power at the safety buses.

   The sensors that detect loss of preferred and alternate offsite sources are located in 6.9 kV safety related switchgear buses 1EA1 and 1EA2 for Unit 1 and 2EA1 and 2EA2 for Unit 2. The scheme consists of instantaneous undervoltage relays which initiate tripping of the source breakers via time delay pick up relays.

   Loss of voltage detector relay setting is selected to preclude operation during momentary low voltage conditions that prevail during large motor starting. The selected setting is to

provide a motor terminal voltage of ≥75% of motor rated voltage and it is lower than the lowest momentary voltage fluctuation for all plant load conditions. Settings for the time delay pickup relay is set long enough to preclude their operation during a three phase fault when system voltage could drop below the undervoltage relay setting, for a few cycles, until the fault is removed by opening the appropriate circuit breakers.

2. Undervoltage protection for Degraded Grid Voltages

Degraded grid undervoltage protection is applied at the 6.9KV and 480V safety related buses as shown in Figure 8.3-18. The Degraded bus undervoltage relays are set to provide a motor terminal voltage of ≥90% of motor rated voltage for motors fed from the bus. These relays via time delays will trip the 6.9KV bus source breakers to assure that the bus loads exposure to degraded voltage is limited to 60 seconds. In the event of an 's' signal, after the degraded condition has been confirmed that it is not due to a motor start, the Preferred source breaker is tripped instantly and the Alternate source breaker is tripped after a time delay, if alternate source does not restore the bus voltage.

At the 480V bus, one set of Low Grid undervoltage relays, set at voltages higher than the degraded undervoltage relay settings, via time delays will initiate an alarm to indicate a degrading grid. In the event of an 's' signal, after the low grid condition has been confirmed to persist, the 6.9KV bus preferred source breaker is tripped instantly and the alternate source breaker is tripped after a time delay if the alternate source does not restore the bus voltage.

3. Undervoltage protection for 6.9KV Dead Bus (6.9KV Class 1E bus loss of voltage)

These relays monitor the loss of bus voltage and are set to assure that the bus voltage has decreased to a low enough value to be energized from another source and not result in equipment damage. After a time delay to allow bolted three-phase faults to be cleared by over current protection at the bus incoming breaker, the relay will trip all the 6.9KV motors, provide an alarm indicating loss of bus voltage, and permit the alternate source breaker to be closed to the 6.9KV bus. The relay also starts the D/G after a time delay to allow for the alternate source breaker to be closed.

Degraded voltage conditions are annunciated by the operation of voltage relays on the high side of the startup transformers which detect/alarm small voltage variations in the offsite power system grid voltage when outside the range stated in Section 8.2. The second level undervoltage relay set points are selected above the minimum out of tolerance values for the 6.9KV and 480 V safety related buses (switchgears and load centers) provided in Table 8.3-1C in order to allow continued operation of equipment without any damage. The degraded grid undervoltage protection relay settings assure a minimum of 90% of motor rated voltage at the motor terminals during steady state conditions. These relay settings, in conjunction with the settings of loss of power relays, assure that, on their actuation, the motors are not exposed to a sustained voltage of less than 75% of their rating and exposure to a voltage between 75% to 90% of motor rating is limited to a maximum of 60 seconds to preclude any motor damage. Motor damage on bus reenergization is precluded by the dead bus relay setting which assures that the bus residual voltage has decreased to a low enough value, before allowing closure of the alternate source breaker, such that on bus reenergization the motors are not exposed to a voltage of more than 1.33 V/Hz. Motor damage on bus reenergization by Diesel

Generator is precluded by providing a time delay for bus voltage decay which assures that the bus residual voltage has decreased to a low enough value, before allowing closure of the diesel generator breaker, such than on bus reenergization the motors are not exposed to a voltage of more than 1.33 V/Hz. Automatic tripping of the source breaker to the safety bus by the second level undervoltage relay prevents loss of equipment function due to sustained severe undervoltages. Undervoltage and time delay relay set points are compatible with the equipment capabilities. Low Grid undervoltage relays provide an early alarm for a degrading grid. The safety related equipment can operate continuously at the low grid voltages, however, if the low grid condition persists the safety buses are isolated from the degrading grid on receipt of an SIAS, as a precaution only, to prevent safety related equipment exposure to degrading voltage.

Overvoltage/undervoltage relays coincidence logic are identified in Figure 8.3-18. The undervoltage relays coincidence logic preclude spurious tripping of offsite power source.

4. Automatic Transfer

When the source breakers for the preferred offsite power source are tripped, the Class 1E buses are transferred to the alternate power source by a slow transfer in a manner similar to that described for the non-Class 1E buses. For class 1E busses, the motor trip signals are concurrently initiated with alternate source breaker closing permissive signal.

The alternate power source of Unit 1 safety-related buses 1EA1 and 1EA2 is startup transformer XST1 and the alternate power source of Unit 2 safety-related buses 2EA1 and 2EA2 is startup transformer XST2. The preferred and alternate power source startup transformers (XST1 and XST2) are designed to feed only safety related buses. This eliminates the possibility of overloads on a startup transformer during any mode of plant operation. In the event that the preferred offsite source is lost, the Class 1E buses would automatically transfer to the alternate source. The transfer capabilities of the source feeders to the emergency busses were tested in the Startup Program as described in Table 14.2-2, AC Power Distribution Test Summary. Operation of the unit could continue for a limited period of time based upon the constraints defined in the plant Technical Specifications.

Low voltage (after an appropriate time delay) on the Class 1E bus shall start the respective emergency diesel generators for that bus should the alternate source not return power to the Class 1E buses. The time allowed for a DG start signal, after detection of loss of preferred or alternate offsite source, assures that the DG will start in time to meet the accident mitigation requirements for accidents requiring DG LOOP start. If both the preferred and alternate power sources are not available, the emergency diesel generator will power the bus after it has reached rated voltage and frequency provided the time delay, for bus voltage to decay to an acceptable level, has elapsed and there is no bus fault. The bus will be powered by the emergency diesel generator within 10 seconds after the diesel receives a starting signal.

8.3.1.1.5.3 Sequencer Loading

1. Sequencer

For each unit, two independent and redundant solid-state safeguards sequencer (SSSS) cabinets are provided for sequential loading of the safeguard buses, one for Train A and one for Train B. Each cabinet houses two sequencers, one for the safety injection mode sequencing (SIS) and one for loss of offsite power (blackout) only mode sequencing (BOS). Both Sequencer cabinets are located in the main control room (Elevation 830'-0") of the Electrical and Control Buildings (see Figure 1.2-33). Power to the Solid-State Safeguards Sequencers (SSSS) is supplied from uninterruptible 118-volt ac panels. Each Sequencer cabinet will provide the logic for loading one 6.9 kV emergency bus in a pre-established time sequence in the event of loss and subsequent restoration of bus voltage and/or in the event of a LOCA.

Each sequencer is basically a group of output electromechanical relays operated by solid state logic circuits and timers. The separate and independent timer circuits are initiated for each loading step by solid state logic circuits. The SSSS accepts and combines safety injection signals from the solid-state protection cabinet and undervoltage (UV) input signals from the safeguards bus, and provides output control signals to the safety related equipment required for the safe shutdown of the plant. The output signals are shown in the functional logic diagram Figure 8.3-4. Mode decision logic responds to the status of the inputs by initiating the proper mode of operation.

The sequencer control logics each contain a time delay circuit to provide reset and restart should an undervoltage or safety injection occur during manual test or when the automatic test is operating. This circuit could delay the sequencer start up to one second during the normal auto-testing mode.

During normal operation, the sequencers do not function except for testing. Operation is required upon receipt of a safety injection signal, or loss and subsequent restoration of the 6.9 kV safeguards bus voltage, and for brief periods during periodic testing. Solid-state digital circuits are used for the logic and timing functions; sequencer equipment compatibility with existing systems is accomplished through input isolation buffer circuits and output relays.

Prior to seismic testing, sequencer equipment was aged in accordance with IEEE 323-1974. The System was tested as a completely assembled, operating, deliverable unit, not on a component basis. Contact chatter and time delay of all relays in the Sequencer System were monitored during the seismic tests, and the relays were maintained in their normal state (open or closed), during the tests. In the specific case of the sequencer, the chatter monitors were capable of detecting discontinuities as small as 0.2 milliseconds, and none were detected. (The generally accepted industry criterion for relays is no more than 2 milliseconds.) The System tested fully energized, and all devices were monitored for full operability and functionality before, during and after all qualification tests. In addition, the relays were cycled from energized to deenergized or deenergized to energized state where appropriate relative to their function within the System. The Sequencer System met all performance requirements without any failures or anomalies; all electrical circuits functioned properly during the tests. See Section 3.10B for testing and documentation requirements.

Reliability of each sequencer is assured by continuous testing from the input diode matrix through the logics and timers to the coils of the output relays. If a fault is detected it is alarmed in the control room. A review of the sequencer circuitry reveals that the

sequencer design is relatively direct and simple, not subject to sneak circuits and is highly reliable.

Each SSSS is also designed to combine manual testing with an overlapping automatic test to verify SSSS equipment operation from contact inputs to contact outputs. The manual test facilities include input test switches, output test switches, output blocking switches, local annunciator lamps and digital display. The manual test provides the capability for exercising all of the SSSS logic functions and verifying the time delay setting of each sequencer step output. Additionally, isolated contact outputs are provided for remote annunciation of system blocked for test, operator and auto lockouts operated, measurement of the time delay of each sequencer step output and input status.

The automatic test provides the capability for continuous surveillance of the SSSS operation from the logic input signals through the logic and counter states and up to and including continuity of the output buffer and relay coils. The automatic test does not interfere with system requirements or cause any output relay actuation during normal system operation. The automatic test monitors the SSSS, and upon occurrence of any improper response, displays the step number of the failed test and energizes a fault relay for remote annunciation. The automatic test may be conveniently interrupted at any time by means of the control panel AUTO TEST ON/RESET switch. The automatic test consists of four distinct parts: input diode matrix, test input generator, fault logic, and buffer logic. The automatic test sequence is initiated when the AUTO TEST ON/RESET switch is positioned to ON. This action releases the automatic test, resets and allows the test input generator and the input diode matrix to generate the test inputs necessary for testing. When testing the sequencer circuit, or other time dependent circuit, an automatic test frequency is substituted for the circuits normal time base clock frequency to maintain the circuits time response compatible with the operating rate of the AUTO TEST. During this time, the fault logic monitors appropriate outputs to verify SSSS operation. If the fault logic detects an improper response, a fault condition is initiated. All system accuracy and function requirements are maintained with automatic test implementation. Detailed descriptions of the test circuitry are contained in controlled copies of vendor manuals and CPNPP procedures, which are maintained at the plant site.

2. Loading

In the event of safety injection actuation, the following sequence of operation is initiated.

a. The diesel generator sets receive starting signals and the sequencer receives a signal to arm the Safety Injection Sequencer (SIS).

b. All non-Class 1E loads connected to Class 1E 6.9KV and 480V buses are tripped except those which are isolated in accordance with Section 8.3.1.2.1.7a.3.

c. Power source for the Class 1E buses is established as discussed above. Diesel generator breaker will close, if required, after the diesel generator rated voltage and frequency have been established provided the time delay, for bus voltage to decay to an acceptable level after both preferred and alternate source breakers are open, has elapsed and there is no bus fault. SIS is started on restoration of bus voltage. Large loads required during a DBA are started in sequence by the

safety injection sequencer. Small loads (less than 20 hp) are generally started in accordance with their respective circuit logic. See Table 8.3-1 for details.

This mode functions to recognize a one-out-of-six condition of the safety injection input signals from the solid-state protection system cabinet without a UV condition. A single safety injection signal, without a UV condition, initiates the Safety Injection Sequencer (SIS) timing cycle. The SIS provides 10 independent, time-separated, sequential loading signals to equipment loads listed in Table 8.3-1. A two-out-of-six (or more) condition causes SIS circuits to function in a like manner. Additionally, the two-out-of-six condition causes the SIS to generate SIS auto-lockout and SIS operator lockout signals. The last SIS step, in addition to providing an output loading signal, also provides a reset signal to SIS operator lockout circuits. The SIS sequential loading signals can be reset manually; this also resets the SIS auto-lockout signals.

On loss of both preferred and alternate offsite sources, the incoming breakers on the source buses are tripped or prevented from closing if open.

If both offsite sources are lost (blackout), but no “S” signal is present, the following sequence of operation is initiated:

a. Undervoltage signal arms the Blackout Sequencer (BOS) and starts the diesel generator sets.

b. Undervoltage shed the required loads from the Class 1E buses. The load shedding system consists of shedding of loads at three levels.

   1. Loads powered from Class 1E 6.9kV switchgear are shed by undervoltage relays when the bus voltage decays to approximately 29.3 percent of the rated voltage.

   2. Loads powered from Class 1E 480V AC switchgear are shed by undervoltage relays when the bus voltage decays to approximately 70 percent of the rated voltage.

   3. Loads powered from Class 1E 480V AC MCC are shed automatically on loss of power be deenergization of circuit holding coils which are powered from the same source as the MCC.

c. Power source for the Class 1E buses is established as discussed above. Diesel generator breaker will close, if required, after the diesel generator rated voltage and frequency have been established provided the time delay, for bus voltage to decay to an acceptable level after both preferred and alternate source breakers are open, has elapsed and there is no bus fault. The BOS is started on restoration of bus voltage. Large loads required during a Loss of Offsite Power (blackout) mode are started in sequence by the blackout sequencer (BOS). Small loads (less than 20 hp) are generally started in accordance with their respective circuit logic. See Table 8.3-2 for details.

This mode functions to recognize a two-out-of four or three-out-of four condition of the UV input signal from a 6.9 kV safeguards bus with no safety injection signal present. A

two-out-of-four UV condition (true indication of loss of bus voltage) places the Blackout Sequencer (BOS) circuits in a standby condition. When the UV input status returns to a one-out-of-four or less condition (true indication of acceptable bus voltage), the BOS circuits begin their timing cycle and provide 10 independent, time-separated, sequential loading signals to the blackout loads listed in Table 8.3-2. Output relays are shown in Figure 8.3-4.

A three-out-of-four (or more) condition of UV input signals (as shown in Figure 8.3-4) causes the BOS circuits to function as previously described. Additionally, it also causes the BOS to generate BOS auto-lockout and BOS operator lockout signals.

The last BOS step, in addition to providing an output loading signal, also provides a reset signal to the BOS operator lockout circuits. The BOS sequential loading signals can be reset manually; this also resets the BOS auto-lockout signals.

In the event of safety injection, plus blackout, the SSSS functions to recognize the simultaneous or sequential occurrence of UV and safety injection signals. In this mode, the time-step output signals of both sequencers are deenergized and remain deenergized until the status of the UV input returns to normal. When the UV condition returns to normal, the SIS proceeds through its operation as described for safety injection alone. See Figure 8.3-4.

The load shedding function is retained after diesel generators are connected to their respective buses. If load shedding function bypass feature were to be adopted, any malfunction on the bypass system may prevent the required load shedding prior to diesels connected to their buses.

8.3.1.1.6 Safety-Related Power System Equipment Identification

Safety-related power system electrical equipment is uniquely numbered so that identification as safety equipment is evident. The numbering sequence used for Class 1E equipment is different from the one used for non-Class 1E equipment. The equipment numbering system is discussed in Subsection 8.3.1.3. In addition, color-coded nameplates conspicuously identify the major equipment as Class 1E. Plant personnel can determine the train or channel that the equipment is associated with by this color.

Color delineation of the trains and reactor protection instrumentation channels is as follows:

1. Engineered Safety Features (ESF) Systems

Train A	orange
Train B	green

2. Reactor Protection System and ESF Systems at Channel Level

Channel I	red
Channel II	white

Channel III	blue
Channel IV	yellow

These color designations are consistent throughout the plant to allow for immediate identification. Cable and cable tray identifications are discussed in Subsections 8.3.1.3 and 8.3.1.4. These standards do not apply to the identification of control panels.

8.3.1.1.7 System Instrumentation and Control

Bus voltage and frequency monitors include the voltmeters for 6900 volts bus 1EA1, 1EA2, 2EA1 and 2EA2, for transformers XST1 and XST2 High-Voltage Sides as well as the frequency recorder for 345KV buses East or West and frequency meter for 6900 volts bus 1EA1, 1EA2, 2EA1 and 2EA2.

Remote instrumentation for the 6900-V Class 1E switchgear consists of ammeters in the Control Room and on the hot shutdown panel for the preferred power source and the alternate power source. The remote instrumentation for the standby power source (diesel generator unit) consists of ammeter, voltmeter, frequency meter, wattmeter, and varmeter in the Control Room and an ammeter on the hot shutdown panel. Various annunciators and bus voltmeters and frequency meters are located in the Control Room. Instrumentation for each 480-V Class 1E switchgear consists of ammeters on the 6900-V switchgear breaker for that switchgear and a bus voltmeter located on the 480-V switchgear. This is shown on Figures 8.3-6 and 8.3-8.

The diesel generator breaker control and synchronizing switches are located in the Control Room for corrective action by the operator. Selector switches located on the shutdown transfer panel and on the hot shutdown panel, and diesel generator breaker control switches located on the hot shutdown panel, are provided for corrective action by the operator in the unlikely event the Control Room becomes inaccessible.

All control switches for 6900-V Class 1E incoming supply breakers, tie breakers, and feeder breakers for Class 1E loads are located on the main control board in the Control Room. In addition, the control switches for Train “A” 6900-V Class 1E incoming breakers, tie breaker, and selected feeder breakers are located on the hot shutdown panel. All 6900-V Class 1E circuit breakers have local test switches at the respective switchgear which are operable only when the breaker is in the “test” (disengaged) position.

Similarly, all control switches for 480-V Class 1E incoming supply breakers, tie breakers, and selected feeder breakers are located on the main control board in the Control Room. In addition, the control switches for Train “A” 480-V Class 1E incoming supply breakers, tie breaker, and selected feeder breakers are located on the hot shutdown panel. All 480-V Class 1E circuit breakers have local test switches at the respective switchgear which are operable only when the breaker is in the “test” (disengaged) position.

Control required for safe shutdown in the event of Control Room uninhabitability is discussed in Section 7.4.1.3.

The described control and instrumentation is used in testing the diesel generator and in monitoring 6900-V and 480-V Class 1E switchgear during normal and Loss of Offsite Power conditions.

Control power for Class 1E equipment is provided as follows:

Class 1E Equipment	Class 1E Control Power Source
6900-V breaker and associated protective relaying	125-VDC system
480-V load center breakers and relaying	125-VDC system
480-V motor control center starters	120-VAC derived through control transformers
Control relays and panels and instrument racks	125-VDC and 118-V uninterruptible AC

8.3.1.1.8 System Testing During Power Operation

Onsite and offsite power sources are not paralleled except for testing of the diesel generators. During the testing mode, only one onsite source is paralleled to the offsite source at any one time. When a diesel generator is not under test, the standby power source is separated from the preferred power source. CPNPP design does not provide for automatic paralleling of these sources by the sequencer. Consequently, no single failure in the sequencer will either compromise separation of redundant portions of these two power sources, or render both preferred power sources and both redundant onsite power sources unavailable.

The transfer of power from preferred to alternate to standby power sources and for load shedding prior to sequential loading are discussed in Subsection 8.3.1.1.5.

The testability of safeguard actuation systems is discussed in Section 7.3.2.

8.3.1.1.9 Sharing of Equipment between Two Units

Nuclear-safety-related loads associated with each unit are powered exclusively from Class 1E systems of that particular unit. However, nuclear-safety-related loads common to both units are powered from Class 1E MCCs and distribution panels which have supplies from each unit.

These dual unit supplies are interlocked to preclude supplying power to one MCC or distribution panel from both units simultaneously. Incoming feeders to train A MCCs or distribution panels common to both units are supplied only from train A power systems of both units (a similar arrangement exists for train B equipment and incoming feeders). This ensures the proper train separation between the equipment common to both units. Train separation is further discussed in Subsection 8.3.1.1.3.

8.3.1.1.10 Basis of Loading

Power requirements for each safety load (Class 1E) are based on motor nameplate rating, pump pressure and flow, or on pump runout conditions. The basis of selection is noted in Tables 8.3-1 and 8.3-2. Continuous duty safety-related (Class 1E) motors have a nameplate service factor of 1.15, except for some totally enclosed Class 1E motors. These motors fall into two categories: first, motors rated 15 percent in excess of the load design brake horsepower (bhp), with a unity nameplate service factor, and NEMA Class-H insulation system, with temperature rise in accordance with NEMA Class-B requirements; and second, totally enclosed air-over fan motors which have an air-over service factor of not less than 115 percent at design conditions and have a nameplate service factor of 1.0.

8.3.1.1.11 Onsite Emergency Power Sources (Diesel Generators)

The standby power system structure is discussed in Subsection 8.3.1. The Diesel Generator System is shown on the main and auxiliary one-line diagrams (Figures 8.3-1 and 8.3-6).

1. Starting Circuits

   Each diesel generator set automatically starts in emergency mode whenever any of the following conditions occur:

   a. Undervoltage on its respective emergency bus

   b. Safety injection actuation signal (SIAS)

   The means of actuating the Safety Injection System are described in Section 7.3.

   The emergency buses are normally fed from the preferred offsite power source, but upon loss of the preferred power supply, automatic bus transfer to the alternate power source occurs after the undervoltage relays on the Class 1E buses have shed the required loads on the Class 1E buses. The diesel generators are not started if the alternate source returns power to the class 1E buses. However, if the alternate source is not available, the diesel generator starts and the breaker will automatically close when the diesel generator has reached rated voltage and frequency. Sequential application of the loads will occur to avoid excessive loading of the diesel generator. For details, see Subsection 8.3.1.1.5.

   Automatic starting and loading logic for diesel generator 1EG1 is shown on Figure 8.3-3. This logic is typical for diesel generators 1EG2, 2EG1, and 2EG2.

   Each diesel generator is capable of attaining rated voltage and frequency and is ready to accept load within 10 sec after receiving a starting signal. Generator reactances and the characteristics of the static exciter and voltage regulator are coordinated to provide satisfactory starting and acceleration of sequenced loads. The exciter regulator system design ensures rapid voltage recovery when starting large motor loads. Voltage drops between sequencing steps do not exceed the limits established in NRC Regulatory Guide 1.9 [3], with the following comment: the voltage may dip below 75 percent of nominal voltage when the diesel generator breaker closes and energizes the two 2000/2666-kVA, 6.9-kV/480-V unit substation transformers supplied from each diesel generator. This dip is due to transformer magnetizing inrush current which exists for

two to three cycles. The diesel generators are designed for recovering to 80 percent of nominal voltage within 10 cycles for this transient. Therefore, the dip may delay motor starting a maximum of 10 cycles. However, since all Class 1E motors have acceleration times within 5 seconds and safe stall times are considerably longer than 10 cycles this potential starting delay has no significant effect on the motors' availability or performance.

Each EDG uses a digital excitation/voltage regulator. This digital exciter/voltage regulator is a Safety Related Siemens THYRIPART generator field excitation unit. This THYRIPART excitation unit utilizes a digital control system consisting of a 32-bit technology module and communications module. This system controls the output of a chopper controller circuit to achieve $\pm$0.5 percent Diesel Generator voltage regulation, and has capability of both manual as well as automatic control.

The THYRIPART excitation units have three modes of operation, two automatic and one manual. The normal operable mode of operation is the AVR mode, in which all exciter regulation functions occur automatically. Under unusual circumstances, a bumpless transfer is manually initiated to the manual (ECR) mode with a trouble indication, in which the field current can be manually adjusted directly from the control room via RAISE and LOWER commands. An open-loop control mode is available in which the entire control of the exciter is conducted manually.

If Diesel Generator voltage goes outside the desired limits, the digital control system is automatically disconnected. The controller then operates in isochronous mode with the magnetics portion of the system maintaining the Diesel Generator voltage within the Technical Specification limits.

Starting of the diesel engines is accomplished by a Compressed Air System consisting of independent and redundant air compressors, receivers, and solenoid valves. Each of the redundant receivers is sized for sufficient compressed air storage for five starts. Section 9.5.6 presents a more detailed description of the starting air system.

Fast starting and load acceptance are enhanced by maintaining engine temperature by heating and forced circulation of cooling water and lube oil. In addition, the units are located in heated and ventilated rooms.

The manual starting of the diesel generators from the Control Room is incorporated into the design to permit periodic testing of the units.

Each EDG has a digital governor system. The digital governor system allows slow starting of the EDG. Slow starting is better for the EDG. It reduces wear by avoiding the full fuel rack starts. Soft start capability is a recommendation of NUREG 1366 and 1431.

Each diesel generator has a manual start/stop switch in the Control Room and on the local panel.

2. Protection Systems

The diesel generator protection systems initiate automatic and immediate protective actions to prevent or limit equipment damage and allow restoration of the equipment

upon correction of the trouble. Automatic tripping of the diesel generators occurs for any of the following reasons, when the diesel generator is started in normal mode.

a. Lube oil low pressure

b. Engine overspeed

c. Crankcase high pressure

d. Generator differential

e. Generator reverse power

f. Jacket water high temperature

g. Generator outboard bearing high temperature

h. Generator loss of excitation

i. Lube oil high temperature

j. Generator negative sequence

k. Generator voltage restrained time overcurrent

l. Generator stator ground

m. Generator field ground

n. Engine high vibration

o. Turbo high vibration

p. Engine bearing high temperature

q. Left or right bank turbo low oil pressure

r. Generator overexitation

s. Generator neutral ground overcurrent

t. Generator underfrequency

With the exception of generator differential and engine overspeed protection, the preceding trips are bypassed when the diesel generators auto start in emergency mode because of a Safety Injection Actuation Signal (SIAS), or associated bus undervoltage or when the diesel generators are manually started in emergency mode. The diesel generator differential relays are General Electric type IJD with a high degree of field-proven reliability.

A diesel generator trouble alarm in the Control Room is provided to alert the operators of any of the abnormal conditions listed previously. Appropriate action can then be taken by the operator as required.

Overcurrent relay protection is provided on each load feeder. Motor feeders connected to the 6900-V switchgear buses are protected by phase and ground overcurrent relays; 480-V feeders are protected by phase overcurrent relays only. See Figures 8.3-5 through 8. If the feeder breaker fails to clear, backup relaying trips the incoming circuit breaker. Smaller motors are connected to MCCs containing combination starters, where short-circuit protection is provided by circuit breakers and overload protection by thermal relays.

Class 1E motor-operated valve motor starters are provided with thermal overload relays connected to alarm only. The valve motors are protected against sustained fault conditions by circuit breakers. The valve motors may be protected by fused disconnect switches if full load currents are less than 1.3 amps.

The unit auxiliary and startup transformers are protected by differential relays and overcurrent backup relaying. Faults within the differential relay zone of the unit auxiliary transformer cause the respective unit to trip and open the unit output 345-kV breaker in the switchyard. The non-Class 1E 6900-V buses then fast transfer to the offsite power source. A fault within the differential zone around either startup transformer opens the appropriate high-voltage breaker in the appropriate switchyard and respective 6900-V breakers and causes the Class 1E 6.9-kV buses to transfer to the alternate power source with no loss of unit operation.

All relay settings are coordinated to isolate a fault condition without interfering with the effective operation of the rest of the system. Settings allow primary relaying to function before the backup relays.

Interlocks are provided to ensure safe and proper operation of the electrical systems. Typical applications are as follows:

a. To lock out all possible sources of power to a bus if a fault exists on the bus

b. To prevent closing of the diesel generator breakers if voltage is present on the bus with the control switch in the automatic mode

c. To prevent closing of the diesel generator breaker until the diesel generator achieves rated voltage and frequency

d. To prevent the two incoming breakers on the Class 1E buses from operating simultaneously in the closed position

e. To prevent paralleling both battery chargers associated with each 125-VDC system

f. To prevent out-of-phase bus transfers

3. Testability and Maintenance

Circuit design provisions incorporate test capability to periodically monitor the operational capability of the safety-related Class 1E systems during power operation. Initially, all safety-related equipment is tested during the startup testing phase.

Diesel generator sets are tested after final assembly and preliminary startup. Site acceptance tests are given to each diesel generator set to demonstrate its required capabilities.

The following tests are administered to certify the adequacy of the units for the intended service:

a. Starting tests

b. Load acceptance tests

c. Rated load tests

d. Design load tests

e. Load rejection tests

f. Electrical tests

g. Subsystem tests

The objectives and requirements of the preceding tests are established in IEEE 387-1977 [32].

Periodic testing of the diesel generators will be performed as specified in the Technical Specifications to verify their continued capability and availability to perform their design function after commercial operation of the plant. Typical tests consist of availability and operational tests as outlined in IEEE 387-1977.

The CPNPP preventive maintenance program is established to prevent failures. Should failures occur, however, the program will function to identify root cause of any malfunctions and to perform the required repairs or component replacement. On completion of the repairs/maintenance, final equipment check is performed prior to starting of any tests to assure a good start. On satisfactory completion of the post-maintenance testing, control of equipment is transferred to the control room operator. These are accomplished by maintenance department procedure.

4. Diesel Generator Fuel Oil Storage and Transfer System

For description of fuel oil storage and transfer system, see Section 9.5.4.

5. Cooling and Heating Systems

a. For description of diesel generator cooling and heating system, see Section 9.5.5.

b. For description of diesel generator starting system, see Section 9.5.6.

c. For description of diesel generator lubricating system, see Section 9.5.7.

6. Instrumentation and Control Systems

The diesel generator starting mode selector switch has remote/local/maintenance positions and is normally in the remote mode of operation position. The only time it is in the local position is for local manual starting in the event of Control Room evacuation and nonroutine testing. If the switch is not returned to the remote position from the local or maintenance position, an alarm in the Control Room persists until the switch is returned to the remote mode. Other manual controls of the auxiliary system of the diesel generator are also alarmed if failure to return to their auto start position would inhibit automatic operation of the diesel generators.

Normal and emergency diesel generator switches (start/stop) are provided in the Control Room and at the local panel.

Control power is obtained from redundant 125-VDC systems. Train A loads of Unit 1 and Unit 2 receive power from batteries BT1ED1 (Unit 1) and BT2ED1 (Unit 2), respectively. Train B loads of Unit 1 and Unit 2 are fed from batteries BT1ED2 (Unit 1) and BT2ED2 (Unit 2), respectively. For details see Subsection 8.3.2.

The source of control power to each switchgear is indicated below:

Unit No.	Battery Source	Classification (Safety Train)	Switchgear No. 6.9kV	480V
1	BT1ED1	A	1EA1	1EB1,1EB3
	BT1ED2	B	1EA2	1EB2,1EB4
	BT1D2	Non-safety	1A1[(a)],1A3[(a)]	1B1, 1B3
	BT1D4	Non-safety	1A2[(a)],1A4[(a)]	1B2, 1B4
2	BT2ED1	A	2EA1	2EB1,2EB3
	BT2ED2	B	2EA2	2EB2,2EB4
	BT2D2	Non-safety	2A1[(a)], 2A3[(a)]	2B1, 2B3
	BT2D4	Non-safety	2A2[(a)], 2A4[(a)]	2B2, 2B4
1 & 2	BT1D2[(b)] and BT2D2	Non-safety	XA1	

a) control power for Unit 1 and 2 RCP breakers is supplied from batteries BT1D5 and BT2D5 respectively

b) via transfer switch

The DC power is required by each diesel generator for controls, alarms, protective relays, air-starting solenoid valves, and generator field flashing from the station batteries.

The following instrumentation is provided to monitor the operability of each diesel generator in the Control Room:

a. Voltmeter

b. Ammeter

c. Frequency meter

d. Varmeter

e. Wattmeter

Instrumentation and alarms provided for diesel generator cooling, starting, lubricating, and ventilation systems are discussed in Sections 9.5.5, 9.5.6, and 9.5.7, respectively. Locations of the previously mentioned instruments in Items a through e are shown on Figure 8.3-6.

Local indication or alarm devices for the standby power system are provided as follows:

a. Bus voltage and frequency

b. Diesel generator status

c. Protective relaying operational alarms

Status indication of safety-related switchgear breakers and MCC breakers is also provided.

7. Prototype Qualification Program

The test program to be implemented for qualification of diesel generator sets is briefly outlined as follows:

a. One full load test is performed on the diesel generator to demonstrate the start and load capability of these units at the two hour rating.

b. Prior to initial criticality of Unit 1, at least 300 valid start and load tests are performed to demonstrate a 0.99 reliability factor with a 50-percent confidence level. This includes all valid tests performed offsite. [270 valid start and load tests are performed from cold ambient conditions with loading to at least 50 percent of the continuous rating within the required 10-sec interval and continued operation until temperature equilibrium is attained. Cold ambient condition is defined as the ambient condition of the diesel generator during normal plant operation, i.e., the diesel generator not running and the water jacket and lube oil heated. 30 valid start and load tests are performed from design hot equilibrium temperature conditions (normal operating temperature equilibrium conditions) with loading to at least 50% of continuous rating within the required 10 second interval.] The onsite testing is to be performed using the diesel generator auxiliary systems and the actual connected loads.

A failure rate in excess of one per hundred in a total of 300 start and load tests requires further testing, as well as a review of system design adequacy.

At least five on-site start and load tests are required to be performed following installation of each diesel generator unit.

c. The diesel generator supplier has performed in his facility one full load test and two margin tests to demonstrate capability in excess of the design requirements on one CPNPP unit.

The seismic testing and analysis of the diesel generator set is performed per IEEE 344-1975 [26].

8.3.1.1.12 Class 1E Equipment Design Criteria

1. All safety-related continuous duty Class 1E motors are sized with a nameplate service factor of 1.15, except for some totally- enclosed Class 1E motors. For service factor of totally-enclosed Class 1E motors see Subsection 8.3.1.1.10.

2. All safety-related Class 1E motors are designed to accelerate their driven loads with 80 percent of the motor rated voltage available at the terminals except for Class 1E Motor Operated Valve (MOV) motors. For Class 1E MOV motors, the available voltages at motor terminals are evaluated for adequacy of MOVs to perform their functions.

3. Motor starting torque is selected based on load speed torque curves and combined wk^2 of motor and driven load for the above terminal voltage and acceleration time (less than five seconds) requirements. In accordance with the loading sequence established in Table 8.3-1, motor acceleration time is specified to achieve motor rated speed in less than five seconds. Motor driven loads not requiring sequencing such as fans have acceleration times in excess of five seconds.

   In addition some fan motors that are part of the sequencing cycle also have acceleration times in excess of five seconds, which will not adversely affect the safety related system performance.

4. The minimum motor torque margin over pump torque through acceleration period is 20 percent for the BOP motors. For Class 1E pump motors furnished by Westinghouse as part of NSSS, the minimum margin of motor torque over the pump full load torque (as defined by the pump speed/torque curve) is sufficient to accelerate the driven equipment within five sec and with 80 percent of rated voltage at the terminals from standstill to operating speed.

5. Motor insulation is selected on the basis of ambient temperature and expected temperature rise based on worst-case loading conditions. In general, the motors have Class B insulation.

6. All 6.6-kV motor stator windings are provided with two temperature detectors embedded in each phase. In case a temperature detector fails, the temperature detectors are abandoned in place and may be replaced when the motors are rewound.

7. Interrupting capacities of switchgear, load centers, motor control centers, and distribution panels are selected on the basis of short-circuit calculations. Transformer impedances

are selected to permit starting of the largest motor on the bus without exceeding a maximum voltage drop of 20 percent and at the same time remaining within the interrupting and momentary capabilities of the breakers.

8. Electric circuit protection is provided to prevent damage to the equipment, maintain operational continuity, and reduce the safety hazard to plant personnel. Fast-acting relays are used to respond to overload undervoltage or faults on feeders or buses to initiate corrective actions and isolate the affected equipment.

9. System grounding and equipment grounding are provided to reduce the safety hazard to plant personnel.

   The 6900-V system is grounded through a low-resistance and designed to trip on ground faults to protect the 6900-V equipment. The diesel generator units are high resistance grounded to allow the generator to continue to supply power without tripping on a single ground fault condition. The 480-V system is high-resistance grounded with a ground detection scheme. This system does not trip on ground fault condition. For each transformer, a voltage relay device is connected across the secondary of a potential transformer (PT) and the primary of the PT is connected across the grounding resistor. If a ground fault occurs, one of these relays will pick up; a ground fault condition in the 480-V system or in the Diesel Generator System is then annunciated in the Control Room.

   The grounding grid of the plant is designed to achieve a ground resistance of less than 0.5 ohm. To achieve this, a ground grid of bare copper cables is buried approximately 2.5 ft below grade level. A cable size of 500 thousand circular mils (MCM) is used for the main loop and interconnections and No. 4/0 AWG cable size for equipment ground connections. These criteria are in accordance with IEEE Guide No. 80, 1971 [40].

8.3.1.1.13 118-V Uninterruptible AC Power

The 118V AC single phase, 60HZ, grounded uninterruptible power is supplied to critical instrumentation and control circuits. 118V AC Class 1E, UPS is described in Section 7.6.1.1. Each unit has two non Class 1E uninterruptible power supplies (UPS) for BOP, non Class 1E, instrument and control systems. In addition each unit has two uninterruptible power supplies (UPS) for the plant computer and other plant loads. Each UPS consists of an inverter, automatic static switch and a manual bypass switch.

For details see Figures 8.3-15, 8.3-15B and 8.3-15C. Each Class 1E inverter receives incoming power supply from the class 1E DC switchboard. The DC switchboard is normally fed from the battery charger. The battery charger receives its incoming power from a class 1E motor control center that has access to the two offsite sources and one onsite source.

In case of loss of the battery charger, the station batteries will feed the DC switchboard and there will be no interruption of power to the inverter loads.

In the absence of inverter output, the static switch disconnects the inverter from the load and connects the load to the alternate supply line from the bypass (nonregulating) transformer within 1/4 cycle. The manual bypass switch operation is make before break.

Each bypass transformer receives incoming power supply from a Class 1E 480-V motor control center. The inverter will automatically resynchronize with respect to frequency and phase with the bypass source following a loss and restoration of this reference source. Under normal operating conditions, the static transfer switch connects the inverter to the load. However, a manual bypass transfer switch, provided for equipment maintenance, can be used to bypass the static switch and supply power to the load directly from the bypass transformer. Operation of the bypass switch to any position will not cause power interruption to the load. Bypassing of the static switch or inverter is annunciated locally and in the Control Room. In the case of inverter supplying power to the plant computer and other non-Class 1E instruments, the DC power input is provided from the non-Class 1E 125/250 VDC system.

The AC instrument buses have two incoming circuit breakers to power the loads from either the UPS or directly from the bypass transformers. Common AC instrumentation buses have two incoming circuit breakers to power the loads from either Unit 1 AC instrumentation bus or Unit 2 instrumentation bus. These manually operated circuit breakers are mechanically interlocked to prevent paralleling of both sources.

The mechanical interlock between the bypass source and the inverter source breakers of panels 1EC1, 1EC2, 1EC5, 1EC6, 2EC1, 2EC2, 2EC5, 2EC6, 1PC1, 1PC2, 1PC3 and 1PC4 may be removed during inverter maintenance. When the interlock is removed, appropriate procedural controls are exercised to prevent paralleling the inverter output with the bypass source.

Class 1E buses feeding common systems loads shared by both units receives power from buses having an incoming manual transfer switch that can select power from either unit. Transfer switch design is such that power can not be supplied from both units simultaneously. Train separation is maintained by supplying these shared buses from the same train of both units.

On loss of offsite power and subsequent loss of battery charger output, 118 VAC and 125 VDC buses feeding common loads will be automatically fed by the battery. If the battery charger output can not be restored, by restoration of offsite source or by EDG, during battery duty cycle, the common 118 VAC panels shall be manually transferred to other unit and the common 125 VDC panels shall be automatically transferred to the other unit.

A spare inverter is provided in each train of 118 VAC system. The spare inverter can be manually aligned to substitute any of the four inverters in that train. Procedural controls and interlocks ensure that the spare inverter can feed the loads of only one inverter at a time and the power source of the spare inverter is the same as that of the substituted inverter.

The AC output voltage provided by the inverters remains regulated within the following limits: voltages of 120V +/-2%, Frequency of 60 HZ. +/-0.5%. The inverters are provided with a synchronizing circuit to synchronize its output sine wave with the 120V AC bypass source.

1. Tests and Inspection

   Prior to placing the Class 1E UPS systems in operation, the system components are tested to ensure their proper operation. The inverters are checked for output voltage and frequency, and transfer between normal and bypass sources, while operating on either the normal or bypass supplies. Panel-mounted instruments monitoring the inverter are calibrated and annunciator and static switch operation checked. During plant power

operations, the UPS systems are periodically tested and inspected to ensure their continued capabilities to perform their operations.

The inverter can be removed from service for inspection and test by manually transferring to the bypass power source. The surveillance instrumentation provides continuous monitoring of the system.

8.3.1.1.14 Physical Arrangement of Class 1E Equipment

Physical locations of Class 1E equipment are selected to minimize vulnerability to physical damage. The degree of separation takes into account the potential hazards in a particular area. Separation is achieved by locating equipment and circuits in separate rooms, maintaining distance, or by use of barriers. The potential hazard of non-safety-related equipment failure on safety-related redundant equipment is considered in choice of equipment location or protection.

Class 1E switchgear and equipment located below the probable maximum flood level of the reservoir (elevation 789.7 ft) are protected as described in Section 3.4. Wherever practicable, electrical equipment is located away from mechanical piping in order to minimize damaging effects of pipe ruptures. All floor levels above 810 ft have adequate drainage provisions to preclude accumulation of water if a pipe rupture occurs. Plant levels 810 ft and below are provided with adequate sumps to limit water accumulation.

Location and separation of major Class 1E equipment are shown in Figures 1.2-11 through 1.2-19 and 1.2-32 and 1.2-33. Separation of major electrical distribution equipment is as follows:

1. Unit auxiliary, station service and startup transformers are located outdoors, physically separated from each other as shown on Figure 8.2-1. For fire protection features, refer to Section 9.5.1.

   Lightning arrestors are used to protect the main transformers, station service transformers, unit auxiliary transformers and startup transformers against lightning. Although these transformers are not classified as Class 1E equipment, careful attention is given to the design of these facilities to ensure reliable and continuous operation.

2. Separate rooms in the seismic Category I Safeguards Buildings provide adequate separation for the redundant Class 1E 6900-V switchgear buses and 480-V load centers. These rooms are located above the PMF level. Piping containing fluids is excluded from these rooms. Rooms containing train A equipment are separated from train B equipment by floor elevations with concrete floor slabs having a minimum thickness of 12 inches. Any failure, whether electrical or physical, in one room will not have any effect on the redundant equipment in the second room. The 6900-V Class 1E switchgear rooms are located adjacent to the diesel generator buildings to minimize the length of the cable runs between the switchgear and associated diesel generator and reduce the possibility of mechanical damage to these connections. Additional protection is provided to the generator leads by running the cables entirely in conduits.

3. The 480-V MCCs are located in areas of electrical load concentration. Redundant Class 1E MCCs are located within seismic Category I structures and separated by location in separate rooms, on different floor elevations, or physically spaced a minimum of 20 ft apart to preclude a single failure from defeating the operation of both trains.

4. Two seismic Category I Diesel Generator Buildings, which are part of the Safeguards Buildings, are provided as shown in Figures 1.2-11 and 1.2-17. One building contains diesel generators 1EG1 and 1EG2, installed as part of Unit 1 construction; the second building contains 2EG1 and 2EG2, installed as part of the Unit 2 construction. Separation between redundant diesel generators within each building is accomplished by locating each diesel generator in a separate room partitioned by a concrete wall designed to withstand an SSE, fire, or missiles. Each diesel generator and its associated starting equipment and auxiliaries are located in the same room. This arrangement results in a complete system independent and isolated from the redundant diesel generator and its systems. Each diesel generator is provided with independent room ventilation air intake and independent air discharge and engine inlet and exhaust ducts. Any credible single failure does not immobilize both diesel generator systems (see Section 9.4.8.1).

   For diesel generator combustion, air intake, and exhaust systems, see Section 9.5.8.

   The fire protection provisions for the diesel generators are provided in Section 9.5.1.

5. Containment electric penetration assembly arrangement design provides access for connecting cables, leak testing during operation, and space for removal and replacement. Separation of penetrations meets single-failure criteria.

   Physical separation between redundant circuits is achieved by establishing three independent penetration areas on different floor elevations. Location and separation of penetrations are shown on Figure 8.3-16. Separate penetrations are provided for medium voltage and low voltage power, control, and instrumentation (includes fiber optic circuits) functions. The maximum possible separation between Class 1E electrical penetrations of redundant trains and any large piping penetration is provided to prevent damage from steam line or waterline rupture.

   Redundant penetrations are located at different floor elevations, where floor slabs are a minimum of 12 in. thick. The minimum centerline separation between any two nonredundant electrical penetrations is 2 ft 2 in. Protection Channels I and III penetrations are located at elevation 842 ft 6 inches. Protection Channels II and IV penetrations are located at elevation 870 ft 0 inches. Minimum separation (clear air space) between any two channel penetrations is 3 ft horizontal and 5 ft vertical. The design and qualification tests are in accordance with IEEE 317-1976 [21] and ASME Boiler and Pressure Vessel Code [45].

8.3.1.2 Analysis

The onsite AC, DC, and 118-V uninterruptible AC electric systems are in conformance with General Design Criteria (GDC), NRC Regulatory Guides, IEEE standards, and other applicable criteria as listed in Section 8.1.4 and as described briefly in Section 8.1.5.

A review of the Class 1E and Non-Class 1E busses supplying power to safety and non-safety-related instrumentation and control systems which could affect the ability to achieve cold shutdown was performed. All power supplies are train-related with the exception of the charging pump discharge flow valve, which will fail open upon loss of power. The loss of power to this valve will not affect the ability to achieve cold shutdown, since the valve fails open. A review of the Emergency Operating Procedures found:

1. Alarm and system operating procedures specify the actions to be taken for loss of a Class 1E or non-Class 1E power supply for instrumentation and control. Actions to restore the supply to normal are in the system operating procedures.

2. Abnormal Conditions Procedures (listed in Table 13.5-3) specify alternate instrumentation and/or controls which can be used by the operator upon loss of power to a particular bus.

8.3.1.2.1 Compliance

1. Compliance With GDC 17 [1]

The safety-related systems are designed with sufficient capacity, independence, and redundancy (as described in Subsections 8.3.1 and 8.3.2) to ensure performance of their safety functions assuming a single failure. The offsite electrical power system also provides independence and redundancy (as discussed in Section 8.2) to ensure an available source of power to the safety-related loads.

Upon loss of the preferred power source to any 6.9 kV Class 1E bus, the alternate power source is automatically connected to the bus and the diesel generator starts should the alternate source not return power to the Class 1E buses. Loss of both offsite power sources to any 6.9 kV Class 1E bus, although highly unlikely, results in the diesel generator providing power to the Class 1E bus.

As discussed in Subsection 8.3.1, two independent diesel generators and their distribution systems are provided for each unit to supply power to the redundant onsite AC Power System. Each diesel generator and its distribution system is designed and installed to provide a reliable source of redundant onsite-generated (standby) AC power and is capable of supplying the Class 1E loads connected to the Class 1E bus which it serves.

As discussed in Subsection 8.3.2, four independent Class 1E 125-V batteries and their distribution systems are provided for each unit to supply power to the redundant DC systems. Each Class 1E battery and its distribution system is designed and installed to provide a reliable source of redundant onsite DC power. Each Class 1E battery is capable of supplying power for four hours to the Class 1E loads connected to the Class 1E bus which it serves.

Redundant parts within the AC and DC systems are physically and electrically independent to the extent that a single event or single electrical fault can not cause a loss of power to both Class 1E load groups.

2. Compliance With GDC 18 [1]

The electric power systems are designed to permit inspection and testing of all Class 1E systems. Periodic testing is performed on a scheduled basis to demonstrate the operability and continuity of all safety-related systems and components. The testing capability provided for the diesel generators and Class 1E batteries is described in Subsections 8.3.1.1 and 8.3.2.1, respectively. Testing capability for solid-state safeguards sequencers (SSSS) is discussed in Section 8.3.1.1.5.3. Plant design also provides testing capability of other Class 1E equipment as required by IEEE 308 [20].

3. Compliance With NRC Regulatory Guide 1.6 [2]

The CPNPP design is in compliance with the provisions of NRC Regulatory Guide 1.6.

The electrically powered safety loads, both AC and DC, are separated into two redundant and completely independent load groups for each unit. There are no automatic or manual ties between redundant load groups.

No single failure can prevent operation of the minimum number of required safety loads and loss of any one group will not prevent the minimum safety functions from being performed. Each Class 1E AC bus has access to two offsite power sources and an onsite standby power source. There are no automatic or manual ties between redundant buses.

Two diesel generators are provided for each unit. Each diesel generator is connected exclusively to its associated 6.9-kV Class 1E bus, which ensures independence in the onsite standby power sources.

Each Class 1E DC bus can be energized either by a battery or by one of two battery chargers (one spare) or combination of battery and battery charger. There are no automatic or manual ties between Class 1E redundant DC load groups. Arrangement of the AC and DC systems is described in Subsections 8.3.1 and 8.3.2, respectively.

Because there are no bus ties between redundant load groups, interlocks are not required.

4. Compliance With NRC Regulatory Guide 1.9 [3]

The rating of the diesel generators is based on the maximum continuous load demand. This rating exceeds the sum of the conservatively rated loads. Motor loads are based on nameplate rating, pump runout conditions, or flow pressure conditions. 6600-V motor efficiency is based on design data. Low-voltage motor efficiency is assumed to be 80 percent.

During preoperational testing, the maximum continuous load demand is verified by tests.

Each diesel generator set is capable of starting and accelerating to rated speed all Class 1E loads in the required sequence.

Sequencing of large loads at 5-sec intervals ensures that large motors have reached rated speed and that voltage and frequency have stabilized before the succeeding loads are applied. The voltage may dip below 75 percent of nominal voltage when the diesel generator breaker closes and energizes the two 2000/2666 kVA, 6.9 kV/480-V unit substation transformers supplied from each diesel generator. This dip is due to magnetizing inrush current which exists for two to three cycles. The diesel generators are designed to recover to 80 percent of nominal voltage within 10 cycles for this transient. The effect on the first load group would, therefore, be a maximum possible delay of 12 to 13 cycle after closure of the diesel generator breaker. However, the objective of first load group and subsequent load groups is not affected. During recovery from transients caused by step load increases or resulting from the disconnection of the largest single load, the speed of the diesel generator set should not exceed the nominal speed plus

75 percent of the difference between nominal speed and the overspeed trip setpoint or 115 percent of nominal, whichever is lower. The voltage is restored to within 10 percent of nominal; and the frequency is restored to within two percent of nominal in less than 40 percent of each load sequence time interval. The diesel generator supplier has successfully performed these tests in his facility on one CPNPP diesel generator set.

The prototype qualification test program of

a. Start and load capability at full load, and

b. 300 valid start and load tests

on the diesel generator are discussed in Section 8.3.1.1.11.

5. Compliance With Regulatory Guide 1.32 [7]

The offsite power system includes the preferred design stated in NRC Regulatory Guide 1.32: namely, two immediate access circuits from the transmission network are available to the emergency (Class 1E) bus systems.

Each battery charger is sized to handle the combined steady-state loads while recharging the battery from the design minimum charge state to the fully charged state under all modes of plant operation.

6. Compliance With NRC Regulatory Guide 1.63 [12]

The electric penetration assembly design complies with the intent of NRC Regulatory Guide 1.63.

The propagation of light thru fiber optic cable in the Electrical Penetration Fiber Optic modules does not generate heat. Therefore, the Electrical Penetration seals and Electrical Penetration concrete interface are not impacted by Fiber Optic Circuits. As such, the circuit protection requirements of NRC Regulatory Guide 1.63 are not applicable to Fiber Optic Circuits of Electrical Penetrations.

In reference to Regulatory Position C.1 of NRC Regulatory Guide 1.63, the electric penetration assembly design, for electrical circuits, is capable of withstanding, without loss of mechanical integrity, the maximum current versus time conditions permitted by backup protective devices. The adequacy of penetration protective devices to protect the penetrations is established by detailed calculations which demonstrate that the fault current-versus time conditions for which the penetrations are designed and qualified will not be exceeded.

Circuits using fiber optic cables are not required to have overcurrent protection. The penetration assembly modules for fiber optic cables will only contain fiber optic circuits and, therefore will not impact the fault current vs. time conditions of the penetrations.

The electrical distribution system design incorporates backup protective devices for all power circuits. Control circuits have also been provided with backup protective devices.

Fuses or fusible links within the penetration assembly are not incorporated in the design because of the physical limitations of the standard penetration designs available.

The circuit design complies with IEEE 279 [19] in that the protective devices are redundant. Circuit independence and physical separation are limited in that both protective devices are in series in the same circuit as described in the following paragraphs. IEEE-279 is not applicable to individual penetration circuit conductors since this standard applies to protective and actuation signals that are part of the multichannel systems required to perform safety functions.

Incorporation of online testability, bypassing, manual initiation, and other requirements of IEEE 279 [19] for every electric penetration assembly circuit is extremely difficult to implement and is not required. The application of backup protection devices and periodic testing of primary and backup devices is sufficient to ensure that the penetration assembly integrity is not violated if one device fails to operate.

Protective devices are tested by the manufacturer in accordance with appropriate NEMA and ANSI standards to assure the devices are qualified to perform their protective functions. In addition, periodic testing verifies the ability of protective devices to interrupt during abnormal operating conditions.

The primary and backup protective device schemes for all power circuits are described below. Also described below are the protection schemes for control circuits. Justification is provided where the control level penetration assembly integrity is maintained without primary and/or backup protective devices.

a. 6900-V Circuits

   Reactor coolant pumps are the only 6900-V loads inside the Containment. The primary and backup protection of these circuits is provided by means of a reactor coolant pump breaker and bus incoming supply breakers, respectively.

b. 480-V Switchgear Motor Feeder Circuits

   The primary protection of these circuits is provided by means of feeder breakers. The backup protection of these circuits are provided by means of an incoming bus supply breaker or a bus tie-breaker.

c. 480 Volt Motor Control Centers (MCC) Outgoing Feeders -

   1. For all starter circuits feeding motors and for all feeder circuits, primary protection is generally provided with a circuit breaker and/or starter with a thermal overload relay in series with a circuit breaker as backup protection or two circuit breakers in series for primary and backup protection are provided in each circuit.

   2. For starter circuits feeding motors having full load currents less than 1.3A, primary and backup protection may be provided by means of a fused disconnect switch and a circuit breaker respectively.

d. Control Circuits of 480-V MCC Outgoing Feeders

Two fuses are used in series in the ungrounded leg of each 120V AC control circuit, one as a primary and the other as a backup device.

e. 125-VDC Power and Control Circuits

1. 125V DC For S.O.V.'s -

The primary and backup protection of these feeder circuits is provided by means of fuses and a circuit breaker respectively or two pairs of fuses.

2. 125V DC Miscellaneous Control Circuits -

The primary and back-up protection of these circuits are provided by means of fuses and a circuit breaker respectively or by two pairs of fuses.

f. Rod Control System Lift and Gripper Coil Circuits -

The primary and backup protection for the Lift and Gripper Coil circuits is provided by fuses.

g. Pressurizer Heater Circuits -

1. Control Group -

The primary and backup protection of these circuits is provided by two feeder breakers in series.

2. Backup Groups -

The primary and backup protection of these circuits is provided by the branch circuit breaker and the panel incoming breaker.

h. Motor Space Heaters

1. Heaters of motors fed from 480V SWGR -

Primary and backup protection are provided by fuses and circuit breakers, respectively.

2. Heaters of motors fed from 480V MCC's -

Fuses are used as primary and backup protection devices.

i. A. C. Lighting Panels Feeders and Polar Crane Feeder-

Primary and backup protection are provided by separate circuit breakers.

j. Liquid Waste Process Panel -

Primary and backup protection are provided by means of a fuse and a circuit breaker respectively.

k. RCP Motor Differential Protective CT Penetration Circuits-

During the normal operation of the RCP motor, there is no current in the CT secondary circuits which penetrate the containment. The primary and backup protection of these circuits are provided by means of a RCP motor feeder breaker and bus incoming supply breakers, respectively.

l. Personnel and Emergency Air Locks -

Primary and backup protection are provided by means of fuse and circuit breaker respectively.

m. 118V AC Control Circuits From Miscellaneous Control Cabinets -

Primary and backup protection to the control circuits originating from NSSS Relay Racks, BOP Relay Racks and PASS Containment Isolation Valve Control Panels are provided by means of a fuse and a circuit breaker respectively or two identical fuses in series.

n. Instrument Distribution Panelboard -

The primary and backup protection for the control power feed to the Instrument Distribution Panelboards inside containment are provided by means of two fuses in series.

o. Monitor and Status Light Circuits -

Primary and backup protection are provided by means of two fuses in series.

p. Annunciator Circuits -

Primary and backup protection of these circuits are provided by means of two fuses in the supply unit of the annunciator cabinet.

q. Solid State Isolation Cabinets -

The maximum available short circuit current at the penetration conductors of these circuits is less than the continuous current rating of the conductors. Therefore, the penetration conductors are self protected and primary and backup protection is not required.

r. Fire Protection/Detection System -

Primary and backup protection is provided by fuses.

s. Fuel Transfer System -

115V, AC control circuit conductors of this system penetrate containment. These circuits, including penetration conductors are protected against overcurrent by two fuses in series (primary and backup protection).

t. Emergency Evacuation System Warning Lights -

The primary and backup protection of these circuits is provided by means of a fuse and a circuit breaker, respectively.

u. In-Core Flux Mapping System -

The primary and backup protection for this system is provided by means of two fuses in series.

v. Plant Communication System -

The primary and backup protection for this system is provided by means of a fuse and circuit breaker, respectively.

w. Rod Position Indication Cabinets -

Power circuits from 120V distribution panels. Breakers are used as primary and backup protection devices.

7. Compliance With NRC Regulatory Guide 1.75 [15] and IEEE 384 [31]

The CPNPP design complies with the intent of NRC Regulatory Guide 1.75 and IEEE 384 (Refer to Appendix 1A(B)). Physical separation of redundant safety-related equipment and wiring is achieved by location in separate rooms or by providing barriers. Isolation devices are provided to preclude interaction between Class 1E and associated circuits and non-Class 1E circuits, as described in the following paragraphs.

Electrical isolation methods are used as required in power, control and instrumentation circuits to maintain the independence of redundant circuits and equipment such that protective functions required during and following any design basis event is accomplished. Different types of isolation devices are used for power, control and instrumentation circuits.

Isolation devices meet the criteria and performance requirements specified in IEEE 279-1971, Revision 1, and are qualified in accordance with IEEE 323-1974 and 344-1975.

Associated circuits shall comply with one of the following:

a. They shall be uniquely identified as such and shall remain with, or be separated the same as, those Class 1E circuits with which they are associated.

b. They shall be in accordance with (1) above from the Class 1E equipment to and including an isolation device. Beyond the isolation device a circuit is not subject to

the requirements of IEEE Std. 384-1974, provided it does not again become associated with a Class 1E system.

c. They shall be analyzed or tested to demonstrate that Class 1E circuits are not degraded below an acceptable level.

The following paragraphs describe the various conditions:

a. Power Circuits

The following types of devices are used in the CPNPP design for isolation of power circuits:

1. Circuit breaker coordinated with the upstream protective device and tripped by a safety injection signal.

2. Circuit protective device of a starter coordinated with the upstream protective device and starter contactor opened by a safety injection signal.

3. Two circuit breakers, two fuses or a breaker and a fuse in series, both coordinated with an upstream circuit protective device, and the circuit breakers periodically tested.

The non-Class 1E loads connected to Class 1E power buses are isolated with an isolation device as described above. These power circuit loads are identified in Table 8.3-11 and in the following figures:

Figure No.
8.3-6 (Sheets 1&2)
8.3-8 thru 12

The above figures identify the circuits with non-Class 1E loads listed in Table 8.3-11 which remain associated after the isolation device. Table 8.3-10 identifies the non-safety loads fed by associated cables, after isolation, where separation from internal non-Class 1E circuits within the equipment is not required. The cables that remain associated after the isolation device meet all the requirements imposed on Class 1E cables and are routed with the train associated with their respective Class 1E power source. The Class 1E isolation device combined with Class 1E circuit protection device, as well as the qualification and routing of these cables, assures that any fault in the connected non-Class 1E load will not degrade the Class 1E power source or Class 1E cables routed with the associated cables.

b. Control and Instrumentation Circuits

The isolation devices mentioned below are classified as Class 1E for control and instrumentation circuits. Separation between the Class 1E and non-Class 1E wiring is maintained within the cabinets in which these devices are mounted.

Maximum wiring separation at the isolation device is limited by the physical design of the device.

1. Qualified auxiliary relays provide isolation between Class 1E, redundant Class 1E, and non-Class 1E circuits for both coil to contact and contact to contact isolation. Electrically, Class 1E circuits are equal or superior to non-Class 1E circuits. Physically, Class 1E circuits are subject to more stringent analysis than non-Class 1E circuits. Therefore, devices qualified for non-Class 1E-to-Class 1E isolation applications provide more than adequate train-to-train isolation.

2. Phototransistor coupled pairs (light emitting diode and transistor) provide isolation of Class 1E contacts to non-Class 1E monitoring devices.

3. A SIAS signal provides isolation between Class 1E and non-Class 1E circuits by relay actuation, which opens the circuit.

4. Current Transformers provide isolation between their Class 1E primary circuit and non-Class 1E secondary circuits. This application is based on testing (Reference 46).

5. Two circuit breakers, two fuses or a breaker and a fuse in series, both coordinated with an upstream circuit protective device, and the circuit breakers periodically tested, provide isolation between Class 1E and non-Class 1E circuits.

6. Within the NSSS protection system cabinets, a fuse or breaker, coordinated with the upstream protective device, is an isolation device to prevent malfunctions in Non-Class 1E portions of a circuit from causing unacceptable influences on the Class 1E function of the circuit (Reference 48). This exception to the isolation devices described in the preceding paragraph (5), is applicable only to the NSSS circuit design by Westinghouse. See Section 7.1.2.2.1.

7. Frequency Transducers, provide isolation between Class 1E circuit and non-Class 1E Frequency Indicators.

Cables that remain associated after the isolation device meet all the requirements imposed on Class 1E cables and are routed with the train associated with their respective Class 1E system. The circuit protection and Class 1E isolation device, as well as the qualification and routing of these cables, assures that any fault in the connected non-Class 1E device will not degrade the Class 1E system including the Class 1E cables routed with the associated cables.

Safety-related equipment, exposed raceways, and cables are identified by distinct color markers so that the plant personnel can distinguish, without resorting to any reference material, between the various redundant Class 1E systems and between redundant Class 1E systems and non-Class 1E circuits.

The physical separation and identification of circuits are described in detail in Subsections 8.3.1.4 and 8.3.1.3, respectively.

c. NSSS Instrumentation Power Circuits

Instrumentation power for Unit 1 NSSS is provided from distribution panels 1PC1, 1PC2, 1PC3 and 1PC4. See Figure 8.3-15. These panels power safety loads as well as non-safety loads.

Each non-safety circuit powered from these panels will have a non-safety circuit breaker or fuse connected in series with the panel circuit breaker.

Protection channel wiring, safety-train wiring and non-safety train wiring within panels 1PC1, 1PC2, 1PC3 and 1PC4 will be in different wire bundles. These bundles will be separated to the maximum extent practicable.

The same criteria described above is also applicable to Unit 2 NSSS instrumentation circuits and their respective distribution panels.

d. Lighting System

The non-Class 1E security lighting circuits and the non-Class 1E AC lighting inside the containment building are isolated from their Class 1E power source with two separate Class 1E breakers connected in series. These breakers are coordinated with their supply breakers and will be tested periodically to ensure that coordination is maintained.

The non-Class 1E AC essential lighting circuits are isolated from Class 1E power sources with two separate Class 1E breakers (i.e., the 480V MCC supply breaker and the main breaker within the Class 1E lighting distribution panel) connected in series. These breakers are coordinated with their supply breaker and will be tested periodically to ensure that coordination is maintained.

The non-Class 1E AC essential lighting circuits use interconnecting cable (i.e., from the lighting distribution panel feeder breaker to the lighting load) routed in conduit. The routing of the circuits in conduit ensures the physical and electrical independence from Class 1E circuits beyond the second isolation breaker.

The non-Class 1E DC emergency lighting circuits connected to dedicated batteries are routed in conduit. The routing of the circuits in conduit ensures physical and electrical independence from Class 1E circuits.

The lighting circuits routed in conduit meet the separation criteria of Section 8.3.1.4.

e. Diesel Generator Neutral Ground System

The non-Class 1E diesel generator neutral grounding transformer is connected to the neutral of the Class 1E diesel generator. The diesel generators have 7200-120/240 volt resistance grounding transformers on their neutrals which limit

the ground fault current in the associated 6.9 kV system to a low level. This enables the diesel generators to supply power to safety loads during an emergency with a ground fault on the 6.9 kV system. A voltage relay is connected across the secondary of the neutral grounding transformers.

An analysis has been performed which demonstrates that a fault on the non-Class 1E portion of the circuit will not cause an unacceptable influence on the Class 1E system. If a ground fault occurs in the 6.9 kV safeguards electrical distribution system, while it is being powered by a diesel generator, the associated voltage relay will pick up and activate an alarm on the local diesel generator control panel. In addition, a “Diesel Generator Trouble” alarm will be activated in the Control Room, which will indicate that an alarm condition exists at the local panel. If a safety injection signal does not exist concurrently with the actuation of the voltage relay, a diesel generator trip will occur when a ground fault is detected. If a safety injection signal does exist prior to the actuation of the voltage relay, the diesel generator will not trip and the alarm will notify the operator of trouble.

In addition, the interconnecting cable is routed within the diesel generator room. The cable is routed in dedicated raceway and is inspected to Class 1E requirements.

f. Safety System Inoperable Indication (SSII) Panel Isolation and Separation

The Safety System Inoperable Indication (SSII) panels have input signal circuits originating from dry contacts in Class 1E field devices. The SSII panel indication performs no safety-related function nor is operator manual action required based solely on SSII displays. The equipment is non-Class 1E and is fed from a non-Class 1E power source. The logic between the non-Class 1E power circuits and the input circuits from the Class 1E sources is not electrically isolated based on the following analysis.

The output of the SSII power pack is at 115-VDC which is protected by a 0.5 amp fuse. The circuit to the individual field contact is current limited at the logic card to a value of 0.767 mA by means of a series resistor. In addition, logic panel input power is protected by two 3 amp fuses in series. Field contacts at Class 1E devices are rated for 125-VDC and 0.5 amp or higher, which is more than adequate to handle the current and, as such, a fault at the SSII logic panel will not affect the Class 1E field contacts or devices.

The multiconductor cable between the SSII logic panel located in the control room and the termination cabinet in the cable spreading room meet the requirements of Regulatory Guide 1.75, Revision 1, Regulatory Position C.4 except for Class 1E environmental qualification. The cable materials meet IEEE Standard 383-1974 for the attributes of flame and radiation resistance. The cable is installed in a mild environment. One cable is used per ESF train. The insulation is rated at 600V. Any individual conductor is sized at a minimum #18 AWG while carrying a maximum 0.767 mA (current is limited at the SSII logic card as noted above). The system is protected by a 0.5 amp fuse at the 115-VDC SSII power supply. Based on the above analysis, a fault at the SSII logic panel will not impact the availability of adjacent Class 1E cables with which these associated cables are routed.

g. Non Class 1E Indicating Lights

The emergency diesel generator engine control panel has non Class 1E indicating lights which are connected to a Class 1E power supply and are not provided with isolation devices.

The above indicating lights are located in a mild environment, seismically installed and all cabling is made to Class 1E requirements. Since the lights are seismically installed they will cause no damage to other Class 1E devices in the Control Panel during a seismic event. Hence the only possible failure mode of the lights is open circuiting of the lamp filament which will result in isolation of the light from the Class 1E power supply and loss of indication. Since the lights are for non Class 1E loads (e.g., DG Air Compressor, Fuel Oil Booster Pump, Jacket Water Keep Warm Pump, Pre-lube Pump, Aux Lube Oil Pump, and Aux Jacket Water Pump), opening of the lamp filament and loss of indication is not a concern and it will not degrade the Class 1E power supply.

The above design assures that non Class 1E indicating lights, wired to Class 1E requirements, and seismically installed in Class 1E equipment with no isolation devices will not degrade the Class 1E power supply.

h. Associated cables from non-Class 1E alternate power transfer switch to Class 1E 6.9kV switchgear

CPNPP Class 1E 6.9kV switchgear can be connected to a non-Class 1E alternate power diesel generator (APDG) through a non-Class 1E alternate power transfer switch. With the exception of a brief test window during setup of the APDGs during modes 5 and 6 and in the unlikely event of loss of all AC power, the above cables will remain de-energized during all modes of plant operation and the 6.9kV circuit breakers located in the Class 1E switchgear remain racked out and their locking mechanisms in engaged positions thus isolating the Class 1E 6.9kV bus from the APDG power feed. In view of the above it is concluded that any cable fault (open circuit, short circuit or ground) in the out door section of the above associated cables is of no consequence and it will not affect the integrity of the Class 1E circuits with which these cables are associated.

In Modes 5 and 6 when the APDG may be feeding a train of Class 1E 6.9kV switchgear and during brief period of test window when APDG is being aligned to a train in outage, a cable fault in the out door section of the associated cables will expose the associated portion inside the building to a fault current contributed by the motor loads on the 6.9kV switchgear. The associated cable rating and size are adequate to withstand the magnitude and duration of the fault current provided by the motor loads and as such have no adverse effect on the integrity of the Class 1E circuits with which these cables are associated. Because these cables inside the building are inherently protected and will adequately withstand the exposure due to fault outside the building, Class 1E protection devices to isolate the fault to protect Class 1E circuit with which these cables are associated, are not required.

In view of the above analysis it is concluded that the non-seismic supports and routing of these associated cables outdoor, do not degrade the Class 1E circuit with which these cables are associated. Additionally, Class 1E devices are not required to protect these cables because these cables inside the seismic building are inherently protected from faults caused outside the building.

i. Level Switch Electronics Boxes (X-LY-4849A-1, X-LY-4849A-2, X-LY-4849B-1 and X-LY-4849B-2)

The Class 1E Electronics Boxes (X-LY-4849A-1, X-LY-4849A-2, X-LY-4849B-1 and X-LY-4849B-2) are connected to the Non-Class 1E annunciator in the Spent Fuel Pool Panel CPX-EIPRLV-06. At the Electronics Box, the Class 1E Cables from the level switches and 120V AC power supply cable enter the box from the top where as the Non-Class 1E cables from the annunciator enter the box from the bottom. The cables from the Class 1E Electronics Boxes to the plant computer are Non-Class 1E. The conductors originate at a Class 1E I/O board and is routed through an isolation device to the terminal block within the Electronics Box. To ensure the isolation device is protected from hot shorts, each conductor is independently fused between the isolation device and the terminal block. Two 1/4 amp, 250 VAC Class 1E fuses on the "+" and "-" of the isolator output are used for protection. These fuses will open under an abnormal faulted circuit condition to prevent damage to the isolator. The circuit is considered to be Non-Class 1E after the Class 1E fuses. The conductors are routed away from any Class 1E device inside the Electronics Boxes, and are landed below the annunciator circuits on the terminal block. However, inside the Electronics Box the Class 1E and Non-Class 1E Cables both terminate on the same terminal block. The terminal block is heavy duty, barrier type, rated 600 Volts and 75 Amps AC, with breakdown voltage 13,000 V RMS line to line. The line to line spacing between the terminals is 0.66 inches. Non-Class 1E Cables are rated at 600 V AC and are fire retardant.

The annunciator circuit rated voltage is 12 V DC and the maximum fault current that the annunciator power supply can furnish is limited to 1.3 mA. As the cables are routed in dedicated conduits the probability of these cables being imposed with any other voltage due to external cable faults is precluded. Inside the Spent Fuel Pool Panel the devices are seismically installed and cable terminations made per the requirements of ES-100. There are Non-Class 1E Cables that carry 120 V AC and are terminated in the vicinity of above annunciator cables terminations. Since the cables are trained to terminate on particular terminals, it is not credible that the 120V AC carrying cable terminals will get loose and create a hot short at the annunciator cable terminals that are several terminals away.

A 250 ohm resistor, connected in parallel to the output of the isolation device and mounted on the terminal block, is being used to provide a 1-5 VDC output signal to the plant computer. Train "C" conduit is used to route the cable from the Electronics Boxes to a level 4 tray and is then run to the Safeguards building in this tray. The level 4 tray system, which has level 3 trays running above it, is supported as Seismic Cat. II, at minimum. Therefore, the entire tray system will be substantially rigid in case of a seismic event. If the tray(s), running above the tray system carrying the output cable, were to collapse, the highest voltage level

which could possibly come in contact with the Non-Class 1E cable would not be greater than 120 VAC. Since it has been determined that the isolation device, in conjunction with the fuses, could withstand a transient voltage exceeding 120 VAC, there is no reason to suspect that an accident of any magnitude could induce voltage which would cause a credible failure of any kind. Therefore, an accident will not create a credible failure to a Class 1E device within the Electronics Box. Dedication testing has provided data to show, with the inclusion of the fuses to the output of the isolation device, the isolation device can withstand open circuits, shorts across the output terminals and application of abnormal circuit voltages to the isolator output without damage to the Class 1E input circuit. Therefore, these cables do not pose any new failure modes.

The devices inside the Electronics Boxes are seismically installed, terminations made per the requirements of ES-100, the Non-Class 1E terminals are located below the Class 1E terminals and the wires are trained to terminate on particular terminals. In view of the above it is not credible that Non-Class 1E terminals will get loose and cause a hot short at the Class 1E terminals above them.

The Non-Class 1E Cables that originate from the Spent Fuel Panel CPX-EIPRLV-06 annunciator are wired to the dry contacts of Class 1E relays installed in the Electronics Box. The relay's contact is rated two Amps at 115 V AC, which is more than adequate to handle the maximum fault current of 1.3 mA DC. The Class 1E relays (American Zettler Relay Type AZ2428-C56-40L) used for annunciation purposes do not do any other function. Since the annunciator circuit maximum fault current is limited to 1.3 mA and the circuit voltage cannot be more than 12V DC any faulted condition in the Non-Class 1E cables will have no adverse impact either on the Class 1E Cables, circuits or on the relay contacts.

In view of the above discussion it is concluded that the Non-Class 1E Cables connected to Class 1E Electronics Boxes are acceptable as it will not degrade the operation of Class 1E Electronics Boxes. Hence, the Electronics Boxes (X-LY-4849A-1, X-LY-4849A-2, X-LY-4849B-1 and X-LY-4849B-2) are exempt from separation distances between the Class 1E Cables/Terminations and the Non-Class 1E Cables/Terminations. Also no Electrical Isolation is required between the Electronics Boxes and cable from the annunciators in the Spent Fuel Panel (CPX-EIPRLV-06).

j. Non Class 1E Emergency Diesel Generator Stator RTDs

The Emergency Diesel Generator stator RTDs do not perform a safety related function, and therefore are classified as non-class 1E. The diesel generator vendor has evaluated the various failure modes and determined that the failure of these RTDs have no effect on the safety function of the generator.

RTDs are passive devices. The only credible failure modes for the RTDs are an open circuit or a short circuit. These failure modes can cause false temperature indication. However, the temperature indications derived from these RTDs do not have a safety function. Consequently, any incorrect temperature indications derived will not have an adverse effect on safety.

Unit 1 and Unit 2 Emergency Diesel Generator RTDs are input through a digital multifunction protective device (MPR-1) that generates a common alarm locally as well as a trouble alarm to the control room. This MPR-1 device output alarm functions are non-safety.

k. Associated control cables interfacing with the non-Class 1E control cables at the Instrument Air Compressor Termination Cabinet CP1-CICACO-01A for Unit 1 and at the Instrument Air Compressor Control Panel CP2-CICACO-01B for Unit 2. These associated cables are considered adequately isolated and are exempt from separation requirements where they interface with non-Class 1E circuits at the termination cabinet CP1-CICACO-01A or at the control panel CP2-CICACO-01B. This configuration has been evaluated and found to be acceptable on the following basis:

1. The power for these control circuits is tripped on a SIS. Therefore, during any event where a SIS is present, this circuit configuration can have no adverse effect because the entire circuit is de-energized and a failure of the Non-1E components could not affect the 1E components.

2. Worse case credible potential cable faults have been evaluated. Characteristics of the circuit design including double fuses at the control power transformer for Unit 1 and a fuse/breaker arrangement for Unit 2, ensure that no cable damage results from even the worse case faults and no propagation to nearby Class 1E circuits is credible.

l. Personnel Airlock Hydraulic Unit Power Feeder Control Panel CP1, CP2-BSCPEB-01.

The following analysis demonstrates that non-Class 1E Train C 480V power cables connected to the line and load side of breaker CP1, CP2-BSDSEB-01 located in personnel airlock power feeder control panel CP1, CP2-BSCPEB-01 will not cause an unacceptable influence on Class 1E Train B wiring/cabling powering Class 1E Train B shunt trip coil of the breaker due to lack of physical separation.

The non-Class 1E cables connected to the breaker are 600V Class 1E cables used in a non-1E application and therefore meet IEEE 383 requirements. Shunt trip Class 1E cables are also 600V IEEE 383 rated. These cables are trained and secured within panel CP1, CP2-BSCPEB-01 so as to maximize the degree of spatial separation between them. Breaker CP1, CP2-BSDSEB-01 and panel CP1, CP2-BSCPEB-01 are Class 1E Train B and installed and supported Seismic Category I. All cable terminations to the breaker, non-Class 1E line and load side cables and Class 1E shunt trip cables are terminated to meet the Class 1E cable termination requirements. This precludes any seismically induced failure of the breaker, panel mounting or cable terminations.

The non-Class 1E cables are fire retardant, adequately designed (voltage level and load service) and are protected by at least two breakers in series; therefore, under any cable fault condition, the non-Class 1E cables will be protected. The fault will not propagate or effect the Class 1E Train B cable. Given the maximized

spacing between wiring/cabling, Seismic Category I mounting of the panel, breaker and cable terminations, it is not credible that the Class 1E Train B cables and non-Class 1E Train C cables will short.

Based on the above analysis, the internal spatial separation, seismic panel mounting, Class 1E termination, circuit protection and fire retardant cable assures that any fault in the connected non-Class 1E cabling will not degrade the Class 1E system.

m. Emergency Diesel Generator control Panel CP1-ECCPEC-01 and 02 the Class 1E solenoid operated valves (SOV), which provide the safety class interface between the Safety Class 3 Emergency Diesel Generator Air Receiver Tank and the NNS Air Compressor, operate when both the pressure indicating switch (PIS) (Class 1E) and time delay relay (Non-Class 1E) contacts are closed. The time delay relays are located in the control panels CP1-ECCPEC-01 and 02. The cable between the PIS and the SOV is classified as Class 1E and the cable between the PIS and the time delay relay contact is classified as Associated because the time delay relays are Non-Class 1E. The Associated circuit therefore, also controls the input power to the SOV, and there is no isolation device between them.

The cable used in the Associated circuit is Class 1E and its installation also meets all the requirements of Class 1E cables.

Impact of any open circuit, grounding or shorting of the Non-Class 1E time delay relay contact that is in series with the Class 1E pressure indicating switch contact, on the safety function of the SOV is evaluated as follows:

1. Open circuit of the time delay relay contact.

   The degradation or open circuiting of the time delay relay contact will result in deenergization of the SOV. Deenergization of the SOV is not a concern as in this mode it performs its safety function.

2. Grounding of the time delay relay contact.

   Grounding of the time delay contact could result in non availability of adequate voltage to the SOV thus deenergizing it. As explained above, deenergization of the SOV is not a concern.

3. Shorting of the time delay relay contact.

   Shorting of the time delay relay contact is no different than a closed contact and it will have no adverse impact on the safety function of the SOV as the Class 1E pressure switch contact will control the operation of the SOV.

Based on the above evaluation it is concluded that an isolation device between the above Class 1E to Non-Class 1E circuits is not required.

n. Unit 2 Turbine Driven Auxiliary Feedwater Pump Control Panel (CP2-EIPRLV-48)

CP2-EIPRLV-48 is the Unit 2 Turbine Driven Auxiliary Feedwater Pump (TDAFWP) Control panel. The panel does not serve a safety related function and contains one non-safety related cable along with several Train A associated cables. The non-safety related cable is part of a circuit that provides an annunciation interlock between the lube oil trouble alarm and the tachometer. Power to the Associated cables is tripped upon receipt of an SI signal. The maximum credible fault current in the non-safety related cable is less than the current carrying capacity of the cable and will not affect any of the Associated cables in its vicinity (even touching).

Therefore, the separation between non-safety and Associated Train A cables in CP2-EIPRLV-48 is not required.

o. Non-Class 1E SSW Traveling Screens Differential Level Transmitters fed by a Class 1E Power Supply

The Class 1E Power Supply (X-LQ-4288A, X-LQ-4288B, X-LQ-4289A and X-LQ-4289B) is protected by an internal (1 Amp) fuse. A current regulator limits the current to 45 mA.

Three resistors (internally mounted in the power supply) are connected in series with a 4 to 20 mA level transmitter (X-LT-4288A, X-LT-4288B, X-LT-4289A and X-LT-4289B). The transmitter can be represented as a variable resistor in the loop. A resistor (392 Ω) is used to compensate the resistance of the loop, keeping the current between 4 and 20 mA. The voltage across another resistor (250 Ω) is used to verify that the loop is working correctly. Another resistor (30.1 Ω) is used to provide input voltage to an Operational Amplifier. The Operational Amplifier output is processed to provide an indication or an alarm signal.

If an open circuit occurs, due to a failure of the level transmitter, no current will flow in the loop. The voltage across the 30.1 Ω resistor will not be normal and an indication or an alarm may initiate. If a short circuit occurs, due to a malfunction of the level transmitter, the current flowing in the loop will be greater than 20 mA. The voltage across the 30.1 Ω resistor will not be normal and an indication or an alarm may initiate. A fault to ground of the transmitter will have the same effect as a short circuit. These indications and alarms are not a safety-related function. Therefore, the malfunction of the level transmitters is not a safety concern.

A loop voltage and a short circuit current test on the power supply card, required by the vendor to verify the operability of the card, is performed by connecting a 100 Ω 1 W resistor which simulates a short of the transmitter, the 392 Ω and 250 Ω resistor. The test required by the vendor simulates a more severe case than the failure of the transmitter only. As such, the power supply will not be challenged by the failure of the transmitter only and the failures in the transmitter will not adversely affect the Class 1E power source. Therefore, Non-Class 1E Travel Screen Differential Level Transmitters fed by a Class 1E Power Supply is not a safety concern.

p. Electrical Isolation/Separation of Class 1E Partial Discharge Monitor Bus Couplers for Unit 1 and Unit 2 Station Service Water Pump and Component Cooling Water Pump Motors and Emergency Diesel Generators.

The Bus Coupler consists of a Class-1E, 15 kV rated, non-shielded jumper cable, Class-1E epoxy mica capacitor (EMC), and Non-Class 1E low voltage, low energy coaxial cable for each motor/generator phase connection and a common Non-Class 1E termination box. The termination box is used to connect Non-Class 1E diagnostic equipment, one phase at a time, when partial discharge monitoring is performed.

The 15 kV jumper is spliced to the motor feeder cable. The other end of this jumper connects to the high voltage side of the EMC. The coaxial cable connects to the low voltage side of the EMC and the other end of this coaxial cable terminates at a BNC connector in the termination box.

The EMC is an 80 pico-farad capacitor that has an impediance of 33 meg-ohms at 60 hertz. Thus the EMC essentially acts as an open circuit at the normal operating frequency of 60 hertz. Only the partial discharge pulses (on the order of nano seconds duration and 100-500 mili-volts) are passed through this capacitor. The diagnostic equipment employs 120 VAC (60 hertz) plant power. Any short on the low voltage side would be of insufficient magnitude to damage the 6.6 kV rated windings of the motor or generator. An open circuit on the low voltage side will not affect the performance of the Station Service Water Pump Motors, Component Cooling Water Pump Motors, and Emergency Diesel Generators, since there is no voltage applied to the EMC under this condition. Also, the capacitor essentially acts as an on circuit at this frequency. Therefore, electrical separation is not required.

8. Compliance With NRC Regulatory Guide 1.81 [16]

The CPNPP design is in compliance with the provisions of Regulatory Guide 1.81 with an exception to Regulatory Position C1 as described below.

Safety-related loads shared between both units are powered from common MCCs, 120-VAC panels, 118-VAC panels, and 125-VDC panels as described in Subsections 8.3.1.1.9, 8.3.1.1.13 and 8.3.2.1. Indication of source of power associated with the common electrical equipment mentioned above is provided on a common panel located in the Control Room and accessible to both unit operators.

A single failure at the system level will not affect the capability to automatically supply minimum ESF loads in any one unit and safely shutdown the other unit assuming a loss of off-site power because the redundancy of common buses is maintained the same as redundancy for Unit 1 and Unit 2 buses.

On-site power capacity to energize sufficient seismic Category I equipment to attain a safe and orderly cold shutdown of both the units, assuming the loss of off-site power and most severe design basis event and a single failure in the on-site electrical system, is not compromised as a result of common buses because each unit system is designed to have sufficient capacity to feed common bus loads in addition to the unit specific loads.

The CPNPP design is controlled such that only common loads are fed from common buses except for some DC / 118-VAC common panels which feed Unit 1 loads also and the normal source of power for the panels is Unit 1. This does not affect the capability of any unit to feed these loads adequately. Because the unit specific loads of only one unit are fed from a common panel and the common panel normal power source is the same unit, therefore, under normal operation, the interaction between the units for maintenance and test operation will be no different than what is required for a common panel. The time when such common panel is aligned to the unit other than the one whose specific loads it feeds will be limited, therefore, any additional interaction needed for maintenance and test activities will be limited also.

9. Compliance With NRC Regulatory Guide 1.93 [18]

CPNPP power operation procedure is in compliance with NRC Regulatory Guide 1.93 as described in technical specifications. The power operation procedure is initiated and continued without restriction only when the limiting conditions for operation (LCO) are met. If the LCO are not met, the power operation will be restricted in accordance with the technical specification.

10. Compliance With IEEE 308-1974 [20]

Class 1E electrical equipment and power sources are designed to satisfy the functional requirements under conditions produced by the DBA listed in IEEE 308. The capacity of each onsite Class 1E power source is sufficient to operate all required Class 1E loads during and after the DBA.

Each Class 1E distribution system is capable of transmitting sufficient energy to start and operate all required loads in that system. A failure of any onsite Class 1E power source does not jeopardize the capability of the redundant onsite Class 1E power source to start and run the required shutdown systems.

Separation, redundancy, and independence of components eliminate the probability of a common failure mode. Class 1E equipment is located in seismic Category I structures except as noted in Section 8.3.1.4 item 1 and qualified in accordance with IEEE 344-1975 [26]. Seismic design of electrical equipment is discussed in Section 3.10. Surveillance of Class 1E systems indicates readiness to perform their intended safety functions. Availability and operability of these systems are monitored by means of periodic testing.

All aspects of the electrical station design comply with IEEE 308-1974 with the exception of test intervals for the battery performance discharge test. (See Subsection 8.3.2.)

11. Compliance with IEEE 336 [24] and NRC Regulatory Guide 1.30 [6]

Quality Assurance Program for the CPNPP onsite Class 1E AC power system is based on the requirements of IEEE 336 and Regulatory Guide 1.30. For details see Chapter 17 and Appendix 1A(B).

12. Compliance with NRC Regulatory Guide 1.47 [9]

The surveillance of each on-site Class 1E AC power system operability status is based on the requirements of Regulatory Guide 1.47, augmented by Branch Technical Position ICSB 21.

A system level safety system inoperable indication (SSII) is provided for each train to indicate if the on-site power source is unavailable.

The Diesel Generator Power Window (DG pwr) on the SSII panel is activated by those conditions that render the D-G inoperable for auto start. The same SSII window is also activated if the following conditions exist.

a. Diesel generator remote-local-maintenance switch in local or maintenance position

b. 6.9kV generator breaker control switch in the lockout position

c. Operator manual action

d. Service water system inoperable

e. Loss of 125 volts DC

f. Diesel generator disabled

Although the conditions listed above may not be electrically interlocked with the D-G, it is recognized that they may render the D-G inoperable or, are otherwise important enough to advise the operator of it's existence.

The condition that renders the D-G incapable of responding to an automatic emergency start signal are:

1. 125V DC not available

2. Overspeed trip not reset

3. Differential lock-out relay not reset

4. Remote-Local-Maintenance Switch in local or maintenance mode

5. Starting air pressure low

8.3.1.2.2 Analysis of Uninterruptible Power Systems

Class 1E 118-V uninterruptible AC Power Systems, which provide power to the Class 1E instrumentation and control circuits, are designed to the same criteria as those for the onsite Class 1E power system.

Distribution panels and equipment they feed as a minimum meet the requirements of GDC 17 [1] and 18 [1], NRC Regulatory Guides 1.6 [2], and IEEE 308 [20], 344-1975 [26] and 384-1974 [31].

8.3.1.2.3 Failure Mode Analysis

Verification that the safety-related auxiliary AC and DC systems satisfy the single-failure criteria is demonstrated by the failure mode analysis given in Tables 8.3-3 and 8.3-7. Component failure and the effects of the failure are noted. Item numbers corresponding to those in the tables appear on Figures 8.3-1 and 8.3-13.

8.3.1.2.4 Class 1E Equipment in a Potentially Harsh Environment

Wherever possible, electrical equipment is located to avoid or minimize the effects of potentially harsh environments during all modes of plant operation. All Class 1E equipment is specified to perform its intended function under the maximum expected environmental conditions at the equipment location.

For details, see Sections 3.11N and 3.11B and Appendix 3A. Appendix 3A delineates postulated environmental extremes for Class 1E equipment located in a potentially harsh environment.

Class 1E equipment located in a potentially harsh environment is designed, fabricated, and qualified in accordance with the requirements of IEEE 323 [22] and applicable IEEE standards for particular equipment (e.g., IEEE 382 [29] for valve motor operators, IEEE 383 [30] for cables, and IEEE 317 [21] and ASME Boiler and Pressure Vessel Code [45] for electric penetrations).

8.3.1.3 Physical Identification of Class 1E Power Systems Equipment

The identification method by which onsite power system equipment can be distinguished as redundant Class 1E systems, associated Class 1E circuits, and non-Class 1E systems is described below:

1. Equipment Tag No.

   Electrical equipment has its own tagging scheme developed by equipment type. Many equipment types follow the tagging scheme for mechanical equipment with a modification of the eighth and ninth character. For equipment using a modified mechanical equipment tagging scheme, the eighth character is generally either “E” or “N”. “E” designates equipment which is Class 1E and “N” designates equipment which is non safety-related. The ninth character typically indicates bus voltage.

   Motors supplied with pumps are identified by the same tag numbers as the pumps, usually with the suffix “M” appended

2. Cables and Raceway Tag Nos.

   All Class 1E system cables and the seismic Category I raceway system are identified by nine alphanumeric character tag numbers as follows:

   a. Raceway System

      The fourth character of a cable tray identification number identifies whether or not the given raceway contains safety-related cables. The fourth character is obtained from the first letter of the applicable train or reactor protection channel

color code as described below. For non-safety related raceways, the fourth character is K. The second character indicates the Unit (i.e., Unit 1 = (1); Unit 2 = (2); common areas = (0)).

b. Cables

The second character in the cable number identifies the cable color code. In addition, the first character of each cable number indicates whether the cable is safety train or channel oriented (E), associated train (A), or non-safety related (N). The third character indicates the Unit (i.e., Unit 1 = (1); Unit 2 = (2); common areas (0)). All conduits/cables not given an identification number in the above manner are termed “Unscheduled”. All unscheduled conduits/cables are categorized as non-Class 1E. These include Heat Tracing, Cathodic Protection, Neoweld, communication, Security, Fire Protection, Fire Detection, and branch circuit lighting conduits originating at Lighting Distribution Panels.

3. Color Coding (Identification) System for Equipment, Raceways, Conduits, and Cables (excluding control panels)

In addition to the tag numbers, Class 1E equipment, raceways, and cables in raceways are identified by the following color coding system:

a. ESF System

Train A	Orange (O with a slash)
Train B	Green (G)

b. Reactor Protection System and ESF Systems at Channel Level

Channel I	Red	(R)
Channel II	White	(W)
Channel III	Blue	(B)
Channel IV	Yellow	(Y)

c. Associated Circuits

Associated Train A	Orange with white stripes
(Train AA)	(0 with a slash)
Associated Train B	Green with white stripes
(Train BB)	(G)

d. Non-Class 1E Circuits

Train C	Black (K)

e. Non-Class 1E Cable Raceways and Equipment — Natural raceway color or natural equipment color

f. Electrical Equipment

Electrical equipment is also identified by a color coded label. The label has an outer and inner border. The outer border identified the unit as follows: Unit 1 (Blue), Unit 2 (Yellow), Common (White with black border), No Unit (White). The inner border identifies the train/channel by color. The inner border colors and corresponding train or channel use the same coloring scheme noted above except as follows:

Associated Train A is orange, Associated Train B is green, Channel II is white with a black border. Equipment with both Train A and Train B has a border that is half orange and half green

4. Method of Equipment, Raceway System, and Cable Color Coding (Excluding Control Panels)

a. Equipment

The preceding color coding is applied to the Class 1E equipment on an area which is readily visible (e.g., close to the nameplate or identification tag number).

b. Raceways

Exposed raceways containing Class 1E cables are marked by the color codes described previously in a distinct permanent manner at intervals not to exceed 15 ft and at points of entry to and exit from enclosed areas. These raceways are marked prior to the installation of their cables.

c. Cables

In general, all Class 1E cables and associated cables are jacket color-coded throughout their entire length. Cable jackets requiring field color coding are color coded at intervals not to exceed every 5 feet for exposed cable runs (cable not in raceway, i.e., cable not in cable tray, conduit or pull box) and at each end. One hour fire rated cable has an overall stainless steel sheath. The stainless steel sheath will be field color-coded similar to that of cable jackets. Cable jackets that require field color coding after installation (due to reclassification of cables from associated Class 1E to Class 1E, or vice versa, after their initial pull) will be field color coded as follows:

1. Where entering and exiting equipment, raceway and inside junction/pull boxes.

2. All exposed portions of the cables will be worked at intervals not to exceed five feet.

3. Portions of installed cables in conduit or trays will not be field color coded.

d. Non-Class 1E Equipment, Raceways, and Cables

Non-Class 1E equipment, raceways, and cables in raceways are not marked by color code, but are left in their natural color. For AC Essential Lighting conduits which have been declassified as non-Class 1E, the originally installed color markers are not required to be removed since the conduit number provides identification. In general all non-Class 1E cables have a black outer jacket. However, non-Class 1E cables whose natural color is not black will be field color coded black at intervals not to exceed every 5 feet for exposed cable runs (cable not in raceway, i.e. cable not in cable tray, conduit or pull box) and at each end.

8.3.1.4 Independence of Redundant Systems

The criteria which have been used to establish the minimum requirements for preserving the independence of redundant Class 1E systems are stated in IEEE 308 [20] and 384 [31] and NRC Regulatory Guides 1.6 [2] and 1.75 [15]. Class 1E equipment and circuits are clearly identified on documents and drawings in accordance with IEEE 494-1974 [36] as discussed in Section 8.1.5.2 (Item 5). The electrical cable system for Class 1E systems is described in the following subsections

Physical arrangement and separation between redundant Class 1E systems are based on the potential hazards in the particular area.

Separation of equipment is achieved by one of the following means:

1. Distance

2. Separate rooms

3. Barriers

Possible hostile effects of non-safety-related equipment failure on safety-related equipment are also considered in determining adequate separation of components.

1. Equipment Arrangement

Each diesel generator including its associated auxiliaries is located in a separate room. The electrical switchgear of train A is separated from that of train B by locating them on different elevations.

A separate and independently ventilated room is provided for the 125V Class 1E batteries of each train in each unit. Battery chargers, distribution switchboards, and SUPS of one train are separated from those of other trains by locating them in separate rooms. In general plant areas, Class 1E MCCs and distribution panels of one train are separated from those of the other train by a distance of at least 20 ft, or where it is not possible to

maintain a 20 ft distance, barriers are provided to maintain proper separation. The Control Room and cable spreading area do not contain high-energy equipment such as switchgear, MCC's, transformers, rotating equipment, high-energy piping, or other potential sources of missiles.

The following equipment are located in the Control Building Mezzanine Area (EL-840'-0"):

a. Regulating transformers TXEC3 and TXEC4 (in Room # 148D).

b. Air conditioner unit CP1-VAACTC-01 (in Room # 148D).

c. Air conditioner unit CPX-VAACTC-01 (in Room # 148).

d. Air conditioner unit CP2-VAACTC-01 (in Room # 148C).

The above rooms in the Control Building Mezzanine Area are separated from the Control Room by a seismic Category II partial height gypsum wall and concrete floor. The ratings of these transformers and air conditioners do not categorize them as high energy equipment.

All Class 1E equipment is located in seismic Category I Structures except for the following devices, which by necessity, are located in the non-seismic Turbine Building:

a. Main Turbine, stop-valve limit switches

b. Main Turbine, trip, fluid-pressure switches

c. Main Turbine impulse pressure transmitters PT505 and PT506, associated with bistables PB505A and PB506A respectively.

d. Feed-pump turbine, trip, fluid-pressure switches

For devices A, B and C, see Figure 7.2-1 sheet 16. For devices D, see Figure 7.2-1 sheet 15.

2. Criteria and Basis for Installation of Cables for Class 1E Systems

Separation between Class 1E cables is provided to preserve the redundancy and independence of redundant electrical circuits. The criteria for cable installation are derived from the basis stated previously and are in compliance with the intent of NRC Regulatory Guide 1.75 [15] and IEEE 384 [31]. Compliance with NRC Regulatory Guide 1.75 [15] is discussed in Subsection 8.3.1.2.1., Appendix 1A(B) and Appendix 8A.

3. Cable Routing

Cables are routed in separate raceway systems according to voltage and function as follows:

a. 6.9-kV power

b. Low-voltage power (less than 600-VAC) and 125-VDC power

c. AC and DC control (may contain 125-VDC or 120-VAC power cables provided the current they normally carry does not exceed the maximum ampacity of control conductors in the raceway system).

d. Instrumentation cables

For Class 1E circuits, analog or other low level type signal conductors (potentials less than 100 volts) are not routed in cable trays containing power or control cables (potentials greater than 100 volts). Analog or other low level type signal conductors for non-Class 1E circuits are not routed in cable trays with conductors at AC or DC potentials exceeding 120V AC (RMS) and 140V DC.

In a vertical stack of trays, except for short distances at vertical to horizontal transitions, the highest voltage level is on top, with lower trays descending in order of voltage level, control trays and finally instrumentation trays at the lowest level.

Cables are installed in ladder-type trays, totally-enclosed trays, conduits, and underground ductbanks. In general, the cable tray system conforms to NEMA VE 1-1971 [39], Cable Tray System. Trays requiring seismically qualified supports are analyzed and supports are located as required.

Non-Class 1E instrumentation cables not installed in raceways, are run inside CPNPP Unit 1 Reactor Building for computer inputs from temperature and thermal movement sensors. Non-Class 1E instrumentation cables not installed in raceways, are also run inside CPNPP Unit 1 and 2 Reactor Buildings for data acquisition from Reactor Coolant Pump Motor Stator temperature sensors. All of these cables carry low level signals and they are qualified to the IEEE 383 standard as well as installed to seismic Category II requirements and to meet separation requirements of Regulatory Guide 1.75.

When Class 1E cables are routed between adjacent seismic Category I Buildings, (leave one building and enter another building) one building wall is provided with embedded rigid metal conduit sleeves and the other building wall has a relatively large opening depending on the number and size of embedded sleeves. Class 1E cables are routed between seismic Category I building walls by either of the following methods:

a. When cable tray is installed on the side with wall openings, the tray will either protrude into the opening so that cables will be routed through the embedded sleeves onto cable tray, or embedded sleeves will be extended through the wall opening with short lengths of conduit enabling cables to be routed onto cable tray running along the wall. At the opposite end of the embedded sleeves, continuous conduit or cable tray will be installed.

b. When continuous conduit is run between two such adjacent buildings, a flexible connection is achieved by using liquid tight flexible metal conduit. The flexible conduit is installed on the side with the wall opening.

Class IE cables are routed between non-adjacent seismic Category I buildings via Category I duct banks. The duct banks consist of rigid metal conduits encased in

concrete resting on bedding and backfill materials. Duct bank rigid conduit ends and building rigid conduit ends are connected by means of flexible metal conduits. Both ends of the flexible conduits are provided with liquid tight and threaded connectors. Similar connections are provided at the manholes.

Cable slack is provided for the above conditions to prevent possible damage to Class 1E cables under the maximum possible movement of adjacent seismic Category I Building walls or wall and duct bank relevant to each other. Similarly, cable slack is provided at both the inboard and outboard ends of the Reactor Building's electric penetration assemblies.

4. Cable Separation

The cable and raceway separation criteria are based on preservation of independence of redundant systems. Cables of redundant Class 1E systems are separated from each other as well as from cables of non-Class 1E systems. Cables of redundant Class 1E circuits are run in separate cable trays, conduits, ducts, and penetrations.

Lesser separation distances than those given in Regulatory Guide 1.75, Revision 1, are being used at CPNPP in several locations between Class 1E wiring and non-Class 1E Area Radiation Monitoring detector wiring and Public Address System speaker wiring based on the following:

a. Area Radiation Monitoring detectors utilize Geiger-Muller Tubes and Ionization Chambers. These devices require very low currents but at high voltage levels. Since the power supplies need to supply 1 milliamp or less, they are designed to provide 2 watts under normal operation conditions and have a design limit of 5 watts. The power supply is not capable of igniting a shorted detector cable because of its "fold over regulation" characteristic which turns off even this low current flow. Therefore any damage will be limited to internal damage and will not be propagated to nearby Class 1E circuits.

b. The Public Address System speaker wire is a similar case with both low current and low voltage requirements. (The National Electric Code recognizes such low power circuits under article 725's Class II wiring). The speaker amplifier is designed to provide a maximum of 12 watts at 14 VDC, which is not capable of igniting the circuit under a fault condition. Therefore any damage in speaker wire shall be limited to internal damage and will not be propagated to nearby Class 1E circuits.

Heliax and Radiax radio antenna coaxial cables are used in the non-Class 1E Radio Communication System. The energy carried by antenna cables is not sufficient to cause internally generated fire in these cables and, therefore, separation between these cables and Class 1E cables is not required.

Thermistor is similar in nature to mineral insulated cable and is a thermal detector used in Fire Detection circuits. The energy carried by Thermistor is not sufficient to cause internally generated fires, and therefore separation between Thermistor and Class 1E cables is not required.

Fiber optic cables used in non-Class 1E monitoring circuits carry no electrical energy by themselves and, therefore, are not required to maintain physical separation from Class 1E circuits.

The raceways of one train are separated from those of the other train by locating them in separate structures or on opposite sides of large rooms or spaces. Where this is not possible, separation is maintained as described below or by providing barriers. The Class 1E cables are routed such that any single failure in one train system does not cause a failure in another train system. The separation of associated circuit cables is maintained on a train basis in the same manner and degree as the Class 1E circuit cables with which they are associated.

Where cables are exposed to such potential hazards as pipe whip, flammable material, and missiles, separation requirements are evaluated on a case-by-case basis to ensure an acceptable level of redundant circuit independence.

5. Minimum Separation Requirement

In plant areas which are free from potential hazards such as missiles, external fires, and pipe whip, the minimum separation between redundant cable trays is three feet between trays separated horizontally and five feet between trays separated vertically.

For interaction involving instrumentation cables only, in the non hazard areas (Cable spreading area and the Control Room) and limited hazard areas (Plant areas which are free from potential hazards such as missiles, external fires, and pipe whip), the minimum separation between redundant instrumentation cables and between instrumentation cables and redundant instrumentation trays is one inch horizontally and three inches vertically. These minimum separation requirements for instrumentation cables are based on IEEE 384-1992 as endorsed by RG 1.75 Rev. 3.

In the cable spreading area and the Control Room, the minimum separation between redundant cable trays is one foot between trays separated horizontally and three feet between trays separated vertically.

In general plant areas and in the cable spreading area, these separation criteria are also applied to cables which are not located in raceway and not inside equipment as if the cable were in an open ladder-type tray.

Where plant arrangement precludes maintaining the above minimum separation criteria, the separation requirements described below are applicable. For cables in large power circuits (6.9KV circuits or 480V circuits using #4/0 or larger power cables), separation from cables in redundant large power circuits is provided by a minimum of 1 inch and two barriers. However, if the cable for the large power circuit is in conduit, and

- the conduit is non-safety related, the minimum separation required in any direction between redundant 6.9KV and large 480V power cable trays or cables in air is one inch, or

- the conduit is safety-related and it is below the cable tray side rail or below the bottom of the cable, the minimum separation required between redundant 6.9KV and large 480V power cable trays or cables in air is one inch.

Separation of cables in large power circuits from all other redundant power and control cables is provided by a minimum of 1 inch and one barrier.

A single barrier is provided and 1" separation or the separation described below is maintained for all other power and control cables or raceways. The minimum separation required between redundant conduit and redundant cable tray is 1". Similarly, the minimum separation required between redundant conduit and redundant cables is 1". A minimum separation of 1" is required if one or both of the conduits are power circuits. However, a minimum of 1/8" is required between a Class 1E conduit and a non-Class 1E instrumentation or control conduit. A minimum separation of 1/8" is required for redundant conduits when both are control or instrumentation.

The above minimum separation criteria are in accordance with Regulatory Guide 1.75, Revision 1, [15] and IEEE-384-1974 [31] and have been demonstrated by testing or analysis specifically for CPNPP or have been demonstrated by testing performed by other utilities where the cables are of the same or similar construction as used at CPNPP. Accordingly, the test results and conclusions are applicable to CPNPP installations. The CPNPP electrical separation criteria generally require greater separation distances than demonstrated in the test configuration.

All Nuclear Instrumentation System (NIS) cables are routed in conduit according to their channel assignment. To preclude introduction of noise in the NIS circuits, a minimum separation of 6 feet is maintained between NIS conduits and raceway containing 6.9 kV circuits. Also, a minimum separation of 2 feet is maintained from NIS conduits running parallel to raceways containing electrical noise sources such as low voltage power and rod control cables. Any deviations are justified on a case by case basis to ensure that unacceptable noise is not induced onto the NIS signal cables.

The minimum separation distance between redundant Class 1E and between Class 1E and non-Class 1E equipment and circuits internal to control equipment is six inches. In this case, the wire and cables are flame-retardant with self-extinguishing and nonpropagating characteristics. Other components such as terminal blocks, wire troughs, wire cleats, raceways, cable ties, glastic barriers, and so forth are manufactured from self-extinguishing material.

Separation within the Class 1E inverters listed in Table 8.3-10 between Class 1E train related input cables and the Class 1E channel related output cables is not required since these cables are integrally associated with each other. Procedural controls and interlocks ensure that only one output circuit cable from the spare inverter is energized at a time. The remaining three output cables from the spare inverter remain deenergized and disconnected at both ends. Therefore, the separation between the output cables of the spare inverter internal or external to the spare inverter is not required. However, separation from all other circuits is maintained as required. For the Class 1E Nuclear Instrumentation System (NIS) neutron flux preamplifiers, signal processors, and isolation expansion assemblies listed in Table 8.3-10, separation between Class 1E train related

cables and Class 1E channel related cables is not required inside each cabinet, since their circuits are integrally associated with each other.

Separation between associated circuits and non-Class 1E circuits in fire panels CPX-EIPRLV-29, CPX-EIPRLV-29A, and CPX-EIPRLV-30 (listed in Table 8.3-10) is not required based on analysis. Separation between trains and channels within the Westinghouse-supplied panel, racks and cabinets listed in Table 8.3-10 is not required based on testing or analysis. These circuits carry low energy fire detection control signals and the postulated failure/fault in the associated circuits inside the fire protection local panel does not degrade the Class 1E contacts or degrade the Class 1E function of the fire detection panel based on the following:

a. The associated circuits link normally open contacts of Class 1E auxiliary relays with the non-Class 1E alarm relays. The alarm relays and the alarm functions for CPNPP are non-safety. Degradation of the associated circuits due to their proximity with the 120-V AC black circuits can occur due to imposition of 120-V AC on the associated circuit wires due to a hot short, or a line-to-ground fault. Since contacts of the Class 1E relays in the local fire detection panels are normally open and are required to close only during a fire in the respective fire detection zone, no current could flow through the same under a non-fire condition.

   Occurrence of an electrical fault coincident with an external fire in two different plant areas is not credible because the 120-V cables (1) are rated for 600-V insulation, i.e., no dielectric failure hazard; (2) carry low current for their size (less than 5 Amps), i.e., no thermal hazard; and (3) run internal to the panel, i.e., no mechanical hazard.

b. The intra-panel non-Class 1E circuits are 24-28-V DC circuits energized by a low capacity 120-V AC to 24-V DC transformer-rectifier system. The internal wires are 600-V grade insulated wires which are used for low energy level circuits. The low-level power supply and the printed electronic circuit cards have a very small capability to feed a dead short (a maximum current flow of three amps will open circuit on the circuit cards). This magnitude of fault current is considered too small to jeopardize the associated circuits and the Class 1E equipment associated with them.

Minimum physical separation between Class 1E cables and non Class 1E differential relay (87/ST1) and (87/ST2) protection cables are not maintained per IEEE 384 inside the 6.9kV Class 1E switchgears. The installation is acceptable as analyzed below:

a. Open Circuit - The Class 1E CTs are qualified isolation devices between Class 1E primary (bus) and secondary output. These CTs are used as isolation devices between Class 1E bus and on Class 1E differential relay cables. The cables from CT lead to Class 1E terminal block inside the 6.9kV switchgear are Class 1E and the cables from the Class 1E terminal block to the differential relay terminal are non Class 1E. However, these cables are 600V rated, procured as Class 1E and are qualified to IEEE 838 fire retardant requirement. Any discontinuity of CTs secondary side circuit will cause the CT open circuit. 600V rated cables tested at 2500V for 5 minutes will adequately withstand the momentary CT open circuit high voltage.

b. Short Circuit - The differential relay cables, are adequately sized to carry CTs secondary current corresponding to 3-φ bus fault condition. Since the cables were tested for 2500V for 5 minutes the installation will withstand CT secondary voltage during 3-φ bus fault condition.

c. Hot Short - The output contacts of differential relays are connected to the lockout relay energization circuit which is protected by 20A fuses. The differential relays are mounted in Protective Relay Board (PRB) located inside the Control Room. The PRB is mounted as seismic Cat. II. The differential relay mounting details are similar to equivalent Class 1E relays. Therefore, the “hot short” between the CT lead wires connected to the differential relay coil and relay output contact is not credible and no further analysis has been done.

d. The cable size is such that it will function adequately and will not fail due to circuit voltage and current conditions to which it might be exposed due to open circuit and short circuit condition. The cable will maintain its integrity and will not adversely affect the Class 1E cables in the vicinity of these cables inside the cubicles. Therefore, these non-1E cables used in differential relay protection for startup transformers are not required to meet the minimum separation requirement of IEEE =-384 inside the 6.9kV Class 1E switchgear.

Separation within other equipment listed in Table 8.3-10 is not required since circuits are isolated from Class 1E buses by isolation devices.

Minimum separation for control and instrumentation cables or raceways inside equipment is 1". Conduit to conduit minimum separation is 0". Cables #10 AWG and larger feeding power to control equipment from distribution panels and all power cables inside power equipment maintain 6" separation or are enclosed or separated by a barrier.

Control and instrumentation cables entering control equipment through BISCO fire sealant maintain a minimum separation of 1" and cables #10 AWG and larger feeding power to control equipment from distribution panels maintain 6" separation.

The above separation criteria has been demonstrated by testing and analysis (refer to References 41 and 42) to meet or exceed Regulatory Guide 1.75 [15] and IEEE-384 [31].

For the purpose of electrical cable separation, acceptable barriers include rigid metal conduit, electrical metallic tubing (EMT), flexible metallic conduit, cable tray covers (both solid and ventilated types), cable bus enclosures, equipment and device enclosures, enclosed metal wireways inside equipment, a wrap of woven silicon dioxide, and one hour fire rated materials (thermolag and one hour fire rated cable).

A wrap of woven silicon dioxide, and one hour fire rated cable are considered equivalent to conduit with respect to protection from electrical failures. Thermolag and one hour fire rated cable shall only be used as a Regulatory Guide 1.75 electrical separation barrier when installed to satisfy the requirements described in FSAR Section 9.5.1.2.

When a cable, conduit or tray is protected by One-Hour fire rated Thermo-lag installed to satisfy the requirements as described in FSAR section 9.5.1.2; there is no separation

requirement from the Thermo-lag protected cable, conduit or tray, to the redundant cable, conduit or tray outside the Thermo-lag enclosure as analyzed below:

a. External Cable Fault: The Thermo-lag installation tests have demonstrated to protect the internal cables from damage that would affect their functionality when subjected to an external one hour duration standard time-temperature curve fire. This is a much more intense and longer lasting fire exposure than the one that could be generated from the short duration of heat exposure from the external cable fault.

b. Internal Cable Fault: The Thermo-lag installation also provides adequate protection to the outside cable from fault generated fire inside the enclosure for the following reasons:

    1. The fire resistance property of the material is same regardless of the fire protection.

    2. The burning characteristics of both the IEEE 383 cable and the Thermo-lag are such that any smoldering or burning that may occur during the fault condition will self-extinguish once the cable fault is isolated by breaker/ fuse. In addition tightness of the enclosure will deprive the fire of oxygen necessary to support a significant, long term combustion in the enclosure.

    3. The exterior banding, tie wires and other structural features of the enclosure maintain the enclosure integrity during the external fire test. These exterior banding, tie wires and other structural features will also maintain the structural integrity during the limited heat exposure induced by an internal cable fault.

c. In view of the above, it is concluded that there is no separation requirement from the Thermo-lag protected cable, conduit or tray to the redundant cable, conduit or tray outside the Thermo-lag enclosure.

Metal Clad (MC) cables include copper sheathed (CS) cable, Aluminum sheathed (ALS) cable and Galvanized Steel Sheathed cable (GS). MC cable conductor size is limited to #10 AWG and below with a maximum of four (4) conductors and will be used only in non-class IE, 120 Vac/125Vdc applications. GS cable shall not be limited to 4 conductors for non-Class 1E instrumentation applications.

CS cable is constructed of continuous corrugated 16 mil thick copper tube with no outer jacket and 600V XHHW, 90°C insulation. CS cable will be used only inside the containment and only in the lighting system.

ALS cable is constructed of continuous corrugated 25 mil. thick seamless aluminum tube with an outer thermosetting chlorosulphonated polyethylene jacket and 600V XHHW, 90° C insulation ALS cable will only be used outside of the containment building in the lighting, fire protection, heat tracing and communication systems.

Galvanized steel sheathed cable (GS) is constructed of continuous interlocked 25 mil thick galvanized steel armor with or without an outer jacket. The internal cable is 600V,

90°C, FR-XLPE with an overall jacket. GS cable without an outer jacket is acceptable for use inside containment.

Testing performed by other utilities has demonstrated the adequacy of the above materials to be used as enclosed raceway and barriers for Regulatory Guide 1.75 [15] separation purposes.

a. Flexible Conduit: Tests documented in Reference 43 for Niagara Mohawk Power Corporation's Nine Mile Point Nuclear Station Unit 2 demonstrated the adequacy of BOA stainless steel flexible conduit and Anaconda steel flexible conduit as an enclosed raceway. Anaconda, BOA and similar quality flexible conduit are used at CPNPP. The power cable was manufactured by Okonite. The control cable was manufactured by Rockbestos. The cables are of the same manufacture and similar construction to those used at CPNPP. Accordingly, the test results and conclusions are applicable to CPNPP installations.

b. Ventilated Tray Covers and Cable Bus Enclosures: Tests documented in Reference 44 for Duquesne Light Company's Beaver Valley Power Station Unit 2 (Configuration No. 4) demonstrated the equivalency of a fluted, ventilated tray cover to a solid tray cover for the purpose of physical separation. The test results were also used to justify considering cable bus enclosures the same as enclosed raceway. Both the power cable tested and that used at CPNPP are of the same manufacture and similar construction. Cable tray, tray covers and cable bus enclosures used at CPNPP are of similar design and construction as those tested/ analyzed for Beaver Valley 2 and accordingly, the test results and conclusions are applicable to CPNPP installations.

c. Protective Wrap: Tests documented in Reference 44 for Duquesne Light Company's Beaver Valley Unit 2 (Configurations 1 and 2) concluded that cables covered with Siltemp protective wrap and 3M No. 69 glass tape combined with a 3/8 in. air space provides adequate protection regardless of whether the faulted cable is within the wrap or outside of the wrap. The results justify considering the protective wrap equivalent to a conduit with respect to protection from electrical failures. The power and control cables tested are of the same manufacture and similar construction to those used at CPNPP. Accordingly, these test results and conclusions can be applied to the CPNPP installation.

   Ampacity tests included in the same report demonstrated that no additional derating, beyond design ampacities, was required when a cable was enclosed in protective wrap. Design ampacities for cables used at CPNPP are similarly derated to those tested (from ICEA table values), and need not be additionally derated.

d. Metal Clad (MC) Cable: MC cable includes Aluminum sheathed (ALS) cable, Copper sheathed (CS) cables and Galvanized steel sheathed cable (GS). Tests documented in Reference 43 for Niagara Mohawk Power Corporation's Nine Mile Point Nuclear Station Unit 2 and Reference 41 for CPNPP demonstrated the adequacy of BOA stainless steel flexible conduit and Anaconda steel flexible conduit as an enclosed raceway.

The ALS cable is enclosed in a 25 mil. thick corrugated seamless aluminum tube which provides mechanical integrity comparable to the 6 mil. thick BOA stainless steel flexible conduit tested in Reference 41. The seamless aluminum tube will contain any cable ignition within the tube. In addition, ALS cable has the annulus between the cable and the tube tightly packed with flame retardant filler materials, which will inhibit flame propagation due to the absence of free-air surrounding the cables. As ALS cable conductor size is limited to #10 AWG with a maximum number of 4 conductors, the cross sectional area of conductors used in the cable is much smaller than the 2/0 fault cable tested in the Anaconda steel flexible conduit in Reference 43. Therefore, the fault currents would be lower than that tested.

ALS cable has thermosetting insulation which is similar to the Anaconda steel flexible conduit tested in Reference 43. The jacketing materials used in ALS cable are also flame retardant.

The conductor material, insulation and filler materials used in CS and GS cable are the same as those used in ALS cable. The CS cable and GS cable construction will exhibit the same flame retardancy characteristics as discussed above for ALS cable. In addition, CS cable is enclosed in a 16 mil thick corrugated copper tube which provides mechanical integrity comparable to ALS cable. The 25 mil thick interlocking Galvanized Steel sheath also provides mechanical integrity comparable to the ALS cable. The GS cable size for #10 AWG and smaller (maximum 4 conductors) is much smaller than the 2/0 fault cable tested in reference 43, therefore the fault currents would be lower than that tested. (GS cable is not limited to 4 conductors for non-1E instrumentation applications). Based on Wyle Laboratories Test #53575 [47], CS cable may be considered as cable in enclosed raceway and one inch separation provides adequate protection to prevent degradation of redundant circuits.

Only MC cable meeting the flame test requirements of IEEE-383 [30] will be used.

Based on the above testing and analysis, MC cable is equivalent to cable inside conduit for electrical separation.

e. One hour fire rated cable:

One hour fire rated cable is used to satisfy the fire safe shutdown requirements as described in FSAR Section 9.5.1.2. The cable is used in power and control circuits outside containment where the total radiation dose is less than or equal to 50 MRADS gamma, and in cable sizes of #8 AWG and smaller. The cable is constructed of a continuously welded corrugated 12 mil thick stainless steel sheath with high temperature nickel-clad copper conductors, glass braid cable jacket and silicone rubber insulation. The cable is Class 1E qualified per IEEE 323-1974 and IEEE 383-1974 for flame retardancy (unaged cables only). See FSAR Section 1A(B), Regulatory Guide 1.131. One hour fire rated cable meets the requirements of ASTM E-119-1971 for a fire resistance rating of one hour. This cable is considered equivalent to cable in conduit for the purposes of electrical separation.

Gaps of 3/8 in. or less at cable tray side rail joints, unfilled square holes 7/16 in. or less on tray side rails and 1/4 in. diameter Ty-rap holes on tray bottom are not considered significant enough to degrade the tray surface as a barrier. These gaps are comparable to openings on ventilated tray covers which have been tested and found acceptable as effective barriers to meet separation requirements per Regulatory Guide 1.75 [15].

f. Stainless Steel Clad Mineral Insulated Cable:

Stainless steel clad mineral insulated cable is used in the Reactor Vessel Level Indication System in the Containment Building. This cable is Class 1E qualified to IEEE 323-1974 and to IEEE 383-1974 for flame retardancy. This cable is constructed with a minimum of 15 mil thick stainless steel cladding which is comparable to the 6 mil thick stainless steel conduit tested in Reference 41. This cable is considered equivalent to cable inside conduit for purposes of electrical separation.

Separation between non-Class 1E and Class 1E circuits or non-Class 1E and associated Class 1E circuits in the Diesel Generator Engine Control Panels CP1/2-MEDGEE-01A and 02A, listed in Table 8.3-10, is not required based on the following analysis. These panels are re-classified as Multi-Train cabinets. Both the AC and DC circuits for the Diesel Generator Engine Control Panels are supplied by a Class 1E power supply. The non-Class 1E circuits in the control panels are electrically isolated by an approved design having two circuit breakers in series for electrical isolation to assure that the Class 1E power source is not adversely affected by a fault in the non-Class 1E circuit.

Internal Train Separation Exemption:

Per Regulatory Guide 1.75, non-Class 1E circuits shall be physically separated from Class 1E circuits and non-Class 1E circuits shall be physically separated from associated Class 1E circuits by the minimum separation requirements. All cables installed in the Diesel Generator Engine Control Panels are flame retardant and meet IEEE-383 flame test requirement. Any non-Class 1E cable fault, short circuit, short to ground, or over load condition will be isolated by an isolation breaker and will not cause the cable temperature to exceed normal operating temperature. The non-Class 1E cables inside the control panel will not be degraded or will not reach the temperature that can affect the Class 1E or associated Class 1E circuits. Open non-Class 1E circuit, have no impact on Class 1E or associated Class 1E circuits. The non-Class 1E cables when maintained within their rated temperature, have no adverse impact on adjacent Class 1E or associated Class 1E cables with no physical separation because the Class 1E and associated Class 1E cables also have the same temperature ratings.

Therefore, the adequacy of the safety-related circuits to perform their safety function is maintained with no separation between non-Class 1E and Class 1E circuits or non-Class 1E and associated Class 1E circuits inside the Diesel Generator Engine Control Panels. Any faults in the non-Class 1E circuits will not compromise the safety function of the Class 1E or associated Class 1E circuits internal to the Diesel Generator Engine Control Panels. Therefore, there is no need for internal electrical separation requirements within Diesel Generator Engine Control Panels CP1/2-MEDGEE-01A and 02A.

6. Cable Spreading Area and Control Room

The cable spreading area is the space below the Control Room where instrumentation and control cables converge prior to entering the control, termination, or instrument panels. This area does not contain high-energy equipment such as switchgear, transformers, rotating equipment, or potential sources of missiles or pipe whip. Flammable material is not stored or installed in this area. Cable constructions are qualified in accordance with IEEE 383 [30]. The circuits in this area are limited to control and instrument functions and those power supply circuits serving the Control Room. Power circuits are not routed in this area, except power cables serving instrument and Control Room distribution panels. These power cables are encased in concrete or run in rigid steel conduits from the point where they enter this area, except for the 120 VAC power circuits, that may be installed using MC cables underneath the Control Room raised flooring.

In this area, a minimum separation of one ft horizontal and three ft vertical is preferred between redundant trays. Where raceway arrangements preclude maintaining the minimum separation distance, the redundant circuits are run in enclosed raceways or barriers are provided between redundant circuits.

Where it is impractical to meet the above requirements, for cables and raceways which are limited to instrumentation and control, the minimum separation distances are as listed in paragraph 8.3.1.4, Item 5.

7. Electric Penetration Area

Except for six penetrations, all individual penetrations are classified according to function and are restricted to exclusive use for power, control, or instrumentation. These six penetrations are exclusively used for six different motor operated valves for both power and control. In addition, penetrations used for the NIS cables are not used for any other purpose.

There are three electric penetration areas, one on each floor elevation. Class 1E penetrations are located on two different floor elevations, one train on each floor. The third (middle) floor area contains the four channels of the NIS and two channels of the RPS system. The remaining two channels of the Reactor Protection System (RPS) are located on the floor where train B penetrations are located. The minimum center line separation between redundant NIS penetrations is six feet. The minimum center line separation between penetrations of redundant channels of RPS, between RPS and NIS, and between these channels and any other electrical penetrations, is 5 feet. The minimum centerline separation between any two (2) non-Class 1E penetrations or any two (2) same train penetrations is approximately 2-1/2 feet. The minimum centerline separation between any Class 1E penetration and non-Class 1E penetration is 3 feet, except for Non-Class 1E fiber optic penetration modules which are installed in Class 1E penetrations.

8. Hostile Environments

Routing of cables for Class 1E systems through an area where there is potential for accumulation of meaningful quantities of oil or other combustible material is avoided.

Where such routing is unavoidable, only one system of redundant cables is allowed in any such area, and the cables are protected by installing them in conduits or solid bottom trays with solid covers. In areas containing potential missiles, physical arrangement, protective barriers, or pipe restraints preclude loss of redundant systems.

9. Sharing of Cable Trays

Non-Class 1E cables are separated from Class 1E cables and from associated cables. Non-Class 1E cables, when they share the same raceway with Class 1E cables or by virtue of power supply connection to Class 1E buses, are associated cables and are so designated. As described in preceding sections, these associated cables are separated from non-Class 1E and from Class 1E channels and redundant train cables with which they are not associated. This separation is maintained throughout the length of the cable (or circuit) until it passes through an isolation device.

Lesser separations are being used in several locations between Class 1E wiring and non-Class 1E Area Radiation Monitoring detector wiring and Public Address System speaker wiring based on analysis. See paragraph 8.3.1.4, Item 4.

10. Spacing of Wiring and Components in Control Boards, Panels, and Relay Racks

Separation of redundant devices and components is accomplished by mounting them on physically separated control boards. Where this mounting is not feasible from a plant operational point of view, and where operational design dictates that redundant equipment be in close proximity, separation is achieved by a six inch minimum airspace or by a fire-retardant barrier. Where this is not possible, an analysis will be provided to show adequacy of separation. Redundant circuits that serve the same protective or control function enter the control boards or panels through separated aperatures and terminate on separate terminal blocks or device connectors.

Where it is impractical to meet the above requirements, for cables and raceways which are limited to instrumentation and control, the minimum separation distances are as listed in paragraph 8.3.1.4, Item 5.

Fiber optic cables used in non-Class 1E monitoring circuits carry no electrical energy by themselves and therefore are not required to maintain physical separation from Class 1E circuits.

11. Cable and Raceway Identification, Fire Protection, and Fire Detection

Raceways and Class 1E cables are identified with unique tag numbers and a color coding system as discussed in detail in Subsection 8.3.1.3. Tag numbers are cross-referenced with cable schedules. Tag numbers and color coding of cables and raceways permit plant personnel to identify Class 1E cables by train and channel without referring to cable schedules.

Cables are installed with consideration given to the cable ampacities. The criteria for cable derating, cable tray fill, and cable fire protection and detection are discussed in Subsections 8.3.3 and 9.5.1.

8.3.1.5 Vital Supporting Systems

The vital supporting systems required for the proper operation of the Class IE load and systems include:

1. Air conditioning, heating, cooling and ventilation systems. (For design bases and description of air conditioning, heating, cooling and ventilation systems see FSAR Section 9.4.)

2. Station Service Water System

   (For design bases and description of station service water system, see FSAR Section 9.2.1.)

3. Component Cooling Water System

   (For design bases and description of component cooling system, see FSAR Section 9.2.2.)

8.3.2 DC POWER SYSTEMS

8.3.2.1 Description

The station DC systems supply power to the plant instrumentation and control under all modes of plant operation. In addition, upon loss of AC power, the DC systems also provide power for emergency lighting and auxiliary turbine-generator motors. The DC Emergency Lighting System is described in Section 9.5.3.

The DC systems for each unit consist of one 125-V, one 125/250-V, and one 24/48-V non-Class 1E battery systems, and two independent and redundant Class 1E 125-V battery systems.

The Class 1E 125-V battery systems supply power to Class 1E loads without interruption during normal operations or DBA conditions. The Class 1E l25-V, seismic Category I battery systems conform to IEEE 308 [20], and NRC Regulatory Guides 1.32 [7], and 1.6 [2].

Each redundant Class 1E 125-V system consists of two independent batteries each having, one main distribution bus with molded case circuit breakers, fusible switches, two static battery chargers (one spare), and local distribution panels (See Figures 8.3-14 and 8.3-14A). Redundancy of components precludes loss of both systems as a result of a single failure. For Unit 1, batteries BT1ED1 and BT1ED3 feed all train A load requirements, while batteries BT1ED2 and BT1ED4 supply train B load requirements. For Unit 2, batteries BT2ED1 and BT2ED3 feed all train A load requirements, while batteries BT2ED2 and BT2ED4 supply train B load requirements. There are no bus ties or sharing of power supplies between redundant trains. Class 1E equipment associated with systems shared by both units receives power from panel boards having an incoming automatic transfer switch which can select power from either unit. Transfer switch design is such that power cannot be supplied from both units simultaneously. Train separation is maintained by supplying these shared panelboards from the same train of both units. Independence and separation are maintained throughout the AC supply

circuitry as well as in the DC distribution network. Non-Class 1E loads are not connected to these systems.

Power is supplied to non-Class 1E loads from the 125-VDC, 125/250-VDC, and 24/48-VDC systems. Each of these systems is completely independent, both of the Class 1E 125-VDC systems and of each other.

The 125-VDC system is primarily a part of uninterruptible power supply (UPS) system to Plant computer and peripherals. The system consists of a 125-V battery, two battery chargers (one spare), and a main distribution bus with molded case circuit breakers (see Figure 8.3-15C). The battery system supplies two 15 kVA inverters (see Section 8.3.1.1.13) which provide the required regulated 118VAC voltage for distribution. The non-Class 1E 125/250-VDC system consists of two 125-V batteries, three 125-V battery chargers (one spare), a main distribution bus with molded case circuit breakers, and fusible switches (see Figure 8.3-14A). The battery system supplies two 10 kVA inverters (see Section 8.3.1.1.13) which provide the required regulated 118 VAC voltage for distribution. The loads on the 125/250-VDC system essentially consist of the following:

1. Turbine-generator emergency bearing oil pump (250-V)

2. Turbine-generator emergency hydrogen seal oil pump (250-V)

3. Feedwater turbine emergency oil pumps (250-V)

4. Control power for non-class 1E switchgear (125-V)

5. Non-Class 1E lighting and distribution panels (125-V)

6. Non-class 1E 10KVA inverters (125-V)

The 24/48-VDC system for each unit is provided for turbine-generator control and instrumentation. The system consists of two 24-V batteries, three battery chargers (one spare), and a main distribution bus. The system in each unit is completely independent of the Class 1E 125-VDC systems and 125/250-V systems described previously.

Implementation of the criteria set forth in the design of the Class 1E 125-VDC systems is described in the following paragraphs.

1. Separation

   The Class 1E 125-V batteries of each redundant train, are located in a separate, seismic Category I room of the Electrical Building at elevation 792 ft. In addition to providing protection against the SSE, the walls of these rooms act as fire barriers to maintain the integrity of the redundant systems. The battery chargers and distribution boards associated with a particular battery are located in a room adjacent to the battery room and are of similar construction. Separation of batteries from associated equipment eliminates possible harmful effects of any corrosive fumes emanating from the batteries, thereby maintaining a high degree of system reliability and availability. Electrical separation is also maintained to ensure that a single failure in one train does not cause a failure in the

redundant train. There is no sharing between redundant Class 1E trains of equipment such as batteries, battery chargers, or distribution panels.

2. Capacity

a. Batteries

Each Class 1E 125-VDC system has the capacity to continuously supply all the connected normal running load while maintaining its respective battery in a fully charged condition. Each battery is capable of carrying the essential load continuously for a period of four hours in the event of a total loss of onsite and offsite AC power. The battery capacity for BT1ED1 and BT1ED2, at an eight-hr discharge rate with a final voltage of 1.75-V/cell, is 1950 Ah. The battery capacity for BT1ED3 and BT1ED4, at an eight-hr discharge rate with a final voltage of 1.75- V/cell, is 1200 Ah. Battery capacities for the Unit 2 Class 1E 125-V batteries are similar

b. Battery chargers

Two 100-percent-capacity static battery charger units are provided for each Class 1E 125-V battery system. Normally, one charger is operating, and the other is kept as a spare. Two circuit breakers connecting these battery chargers to the DC distribution bus are mechanically interlocked such that only one charger remains connected to the bus at any time. Each battery charger has a “Float” and “Equalize” mode. A front panel mounted switch is provided to select either mode of operation. The float and equalize voltages may be independently set at 132 volts 5% and 140 volts 5% respectively. The equalize voltage is set not to exceed 140-V. Output voltage is regulated within ±0.5 percent of setpoint from no load to full load. Backup protection is incorporated by a overvoltage relay mounted on the dc switchboard which annunciates an overvoltage condition in the control room. All connected loads are specified and designed for operation with a maximum input voltage of 140-VDC. Loads are protected from overvoltage by presetting the maximum equalize voltage not to exceed 140-VDC.

Each battery charger is sized to recharge the battery from the design minimum charge state to the fully charged state within 24 hrs while supplying the steady state loads under all modes of plant operation. Input power to these chargers is obtained through independent 480-V, three-phase, AC supply from Class 1E MCCs. Protection is incorporated in the battery chargers to preclude the AC supply source from becoming a load on the battery as a result of power feedback upon loss of AC input power.

3. Ventilation

All battery rooms are ventilated to prevent the accumulation of gases produced during charging operations. Each Class 1E 125-V battery room is provided with redundant ventilation fans and a separate exhaust duct is provided for each room.

In addition, the battery cells are provided with explosion- resistant vent caps that prevent the ignition of gases within the cell from an ignition source outside the cell.

4. Loading

The Class 1E 125-V battery load requirements of Units 1 and 2 are described in Table 8.3-4.

5. Redundancy

Two independent and redundant Class 1E, 125-VDC systems are provided for each unit. Electrical and physical separation as previously described precludes the loss of both systems as a result of a single failure.

6. Testing and Inspection

The preoperational testing of the Class 1E 125-VDC systems is done in compliance with NRC Regulatory Guides 1.41 [8] and 1.68 [13].

Periodic inspection and testing of the DC systems are performed to monitor the condition of the equipment to ensure reliable operation. Visual inspections, liquid level, specific gravity, and cell voltage checks, and performance discharge tests are performed at regular intervals on each battery. All maintenance and testing procedures and criteria for replacement are in accordance with IEEE 450-1995 [35], and Regulatory Guide 1.129 [18D]. Visual checks and performance tests are also scheduled for the battery chargers.

The periodic tests of all Class 1E DC equipment are performed to satisfy the requirements of GDC 18 and 21 [1].

7. Identification of Safety Loads

The safety loads connected to the Class 1E 125-VDC systems are identified in Figures 8.3-14 (Sheets 1 & 2) and 8.3-15B (Sheets 1 & 2). In addition, the table 8.3-4 indicates the maximum length of operating time required for each DC bus total load upon loss of AC power. The method of distinguishing between Class 1E and non-Class 1E loads is defined in Subsection 8.3.1.3.

8.3.2.2 Analysis

The design of the Class 1E 125-VDC systems is in accordance with the requirements of GDC-17 [1], GDC-18 [1], NRC Regulatory Guides 1.6 [2], 1.32 [7], 1.75 [15] and IEEE 308 [20]. Compliance with these criteria is described in Subsection 8.3.1.2.1. The seismic requirements are specified in Section 3.10B.

Redundant power supplies and equipment satisfy GDC 17 for a single failure. A failure mode analysis is presented in Table 8.3-7. Quality assurance, cable routing, separation, and equipment identification are covered in Subsections 8.3.1.2 and 8.3.1.4.

1. Surveillance and Monitoring

Each battery charger is equipped with a DC voltmeter, a DC ammeter, AC failure relays, and low battery voltage relays. Malfunction of the chargers annunciates in the Control

Room. A system level inoperable status indication is provided for the Class 1E 125-VDC system in accordance with NRC Regulatory Guide 1.47 [9].

Battery float and discharge current and distribution bus voltage are monitored at the switchboard and in the Control Room. Ground detection, undervoltage relays, and overvoltage relays are provided on the main distribution buses; off-normal conditions are annunciated in the Control Room.

The overall system design including function requirements, redundancy, capacity, and availability is in conformance with IEEE 308 [20] criteria for Class 1E systems with the exception of battery performance discharge test intervals which is in accordance with IEEE 450-1995.

2. Physical Identification and Separation

The physical identification of the Class 1E DC power systems is combined with the identification of Class 1E AC Power Systems and is described in Subsection 8.3.1.3. The physical separation of the Class 1E DC systems is maintained in accordance with the intent of NRC Regulatory Guide 1.75 [15].

3. Independence of Redundant Class 1E 125-VDC Systems

Redundancy of power sources and distribution equipment is provided in the DC system. This redundancy extends from the station batteries and battery chargers through distribution panels, cabling, and switchgear. Each redundant DC system and its associated distribution equipment can independently provide the required DC power for safe shutdown of the plant.

Each redundant Class 1E 125-V battery system is located in a separate seismic Category I battery room. The Class 1E battery chargers and main distribution buses associated with each Class 1E 125-V battery system are located in a separate seismic Category I room. The local distribution panels, feeders, and control and instrumentation cables raceway system associated with each Class 1E battery system are separated as described in the previous section. Separation of train A and train B battery systems is maintained up through the Class 1E 6900-VAC buses and is consistent with the train designations of such equipment.

The quality assurance program discussed in Chapter 17 ensures compliance with established criteria in IEEE 336-1971 [24] and NRC Regulatory Guide 1.30 [6]. The Class 1E 125-VDC equipment and circuits are identified on documents and drawing in accordance with the requirements of IEEE 494-1974 [36] as discussed in Section 8.1.5.2 (Item 5).

8.3.3 FIRE PROTECTION FOR CABLE SYSTEMS

The Fire Protection System for cables is a part of the integrated system of the fire detection and protection for the entire plant. Cable fire prevention measures such as power cable derating, restricted percentage of cable tray fill, and the installation of nonpropagating and self-extinguishing type cable, insulation, and jacket material are used. These measures are described in detail in the following sections. In general, ionization and thermal type fire detectors

are located in areas of heavy cable concentration to detect a cable fire. These fire detectors form a part of the Fire Detection System installed throughout the plant. The system provides early warning at local panels and in the Control Room to alert the operator and subsequently the plant fire brigade to take immediate action to extinguish a fire.

Portable fire extinguishers and hose stations located throughout the plant are available to extinguish a cable fire.

The fire suppression systems and specific equipment used to extinguish a cable fire are described in detail in Section 9.5.1 for each area containing cables.

8.3.3.1 Cable Derating and Cable Raceway Fill

Cable ampacities are established based on the following:

1. IPCEA P-46-426 (IEEE S-135), Power Cable Ampacities, Volume 1, Copper Conductors, and Volume 2, Aluminum Conductors, 1962.

2. ICEA P-54-440 (NEMA WC-51-1975), Ampacities, Cables in Open-Top Cable Trays, Rev. 2, August, 1979.

3. National Electrical Code (NEC), 1975

4. Manufacturers Standards

Cables are derated in accordance with IPCEA P-46-426 [37], ICEA P-54- 440 [38], the National Electrical Code (1975), and manufacturers recommendations. The following factors are considered in determining the cable sizes:

1. Normal and emergency load currents

2. Short-circuit heating capacity for 6.9-kV loads and 480-V loads fed from the unit substations

3. Voltage regulation

4. Load factor of 100 percent in ductbanks

5. Grouping derating

6. Load diversity

7. Derating for fire stops and tray covers

8. Ambient temperature

The cable type and cable insulation are selected to minimize the rate of deterioration during the design life of the plant as a result of temperature, humidity, and radiation. Environmental Type Tests are performed on cables that are required to function during and following a LOCA.

Cable tray fill criteria generally limit the summation of the cross-sectional areas of control/ instrumentation cables and power cables to a maximum of 40 and 30 percent, respectively, of the usable cross section of the tray. However, these percentages may be exceeded provided the following conditions are satisfied:

1. Cables do not extend above the side rails of the cable tray except as allowed below.

2. For power cables - the thermal rating of the cable is not exceeded.

3. Cable tray support design is adequate.

Cable tray fill for power cables, when sized for maintained spacing, is limited to the requirements of IPCEA P-46-426.

Cable trays may have cables extending above the top of the cable tray siderails. Cables may extend above the top of cable tray siderails if the situation does not result in an electrical or mechanical separation problem and the cables are not routed near potential hazards which may cause physical damage to the cables.

During construction of CPNPP Unit 1, a one time review was made at the request of the NRC to identify where cables extend above the top of Class 1E cable tray siderails and exceed the percent fill limit and can not be corrected by reasonable means. Four such cases were identified at that time. Luminant Power recognizes the need to minimize the number of cases where cables extend above the top of Class 1E cable tray siderails and exceed the percent fill limit and has implemented measures to control future installations such that additional instances will only be implemented subsequent to evaluation by Luminant Power.

Conduit fill for power, control and instrumentation cables is limited to the requirements delineated below:

Number of contained cables	1	2	3 or more
Percent Fill Limit	53	31	40

However, these percentages may be exceeded provided the following conditions are satisfied:

1. Cable pulling tension is not exceeded.

2. For power cables - the thermal rating of the cable is not exceeded.

3. For fire seal application the limits of conduit fill for the qualified seal are not exceeded.

4. Conduit support design is adequate.

8.3.3.2 Fire Detection and Protection Devices

As stated previously, fire detection equipment and protection equipment in the area where cables are installed is described in detail in Section 9.5.1.

8.3.3.3 Fire Barriers and Tray Supports

The fire barriers, where required between redundant trays, are described in detail in Section 9.5.1. The separation between redundant trays is described in Subsection 8.3.1.4.

8.3.3.4 Fire Stops

Fire stops are provided at penetrations in walls and floors designated as fire barriers as described in Section 9.5.1.

REFERENCES

1. 10 CFR Part 50, General Design Criteria For Nuclear Power Plants, February 4, 1972, U.S. Nuclear Regulatory Commission.

2. NRC Regulatory Guide 1.6, Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems, March 10, 1971, U.S. Nuclear Regulatory Commission.

3. NRC Regulatory Guide 1.9, Selection of Diesel Generator Set Capacity For Standby Power Supplies, March 10, 1971, U.S. Nuclear Regulatory Commission.

4. NRC Regulatory Guide 1.22, Periodic Testing of Protection System Actuation Functions, February 17, 1972, U.S. Nuclear Regulatory Commission.

5. NRC Regulatory Guide 1.29, Seismic Design Classification, Revision 2, February 1976, U.S. Nuclear Regulatory Commission.

6. NRC Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment, August 11, 1972, U.S. Nuclear Regulatory Commission.

7. NRC Regulatory Guide 1.32, Use of IEEE Std. 308-1974, Criteria For Class 1E Electric Systems For Nuclear Power Generating Stations, Revision 2, February 1977, U.S. Nuclear Regulatory Commission.

8. NRC Regulatory Guide 1.41, Preoperational Testing of Redundant On-site Electric Power Systems to Verify Proper Load Group Assignments, March 16, 1973, U.S. Nuclear Regulatory Commission.

9. NRC Regulatory Guide 1.47, Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems, May 1973, U.S. Nuclear Regulatory Commission.

10. NRC Regulatory Guide 1.53, Application of Single-Failure Criterion to Nuclear Power Plant Protection Systems, June 1973, U.S. Nuclear Regulatory Commission.

11. NRC Regulatory Guide 1.62, Manual Initiation of Protective Actions, October 1973, U.S. Nuclear Regulatory Commission.

12. NRC Regulatory Guide 1.63, Electric Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants, Revision 2, July 1978, U.S. Nuclear Regulatory Commission.

13. NRC Regulatory Guide 1.68, Preoperational Initial Startup Test Programs for Water-Cooled Power Reactors, Revision 2, August 1978, U.S. Nuclear Regulatory Commission.

14. NRC Regulatory Guide 1.73, Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants, January 1974, U.S. Nuclear Regulatory Commission.

15. NRC Regulatory Guide 1.75, Physical Independence of Electric Systems, Revision 1, January 1975, U.S. Nuclear Regulatory Commission.

16. NRC Regulatory Guide 1.81, Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants, Revision 1, January 1975, U.S. Nuclear Regulatory Commission.

17. NRC Regulatory Guide 1.89, Qualification of Class 1E Equipment or Nuclear Power Plants, November 1974, U.S. Nuclear Regulatory Commission.

18. NRC Regulatory Guide 1.93, Availability of Electric Power Sources, December 1974, U.S. Nuclear Regulatory Commission.

18A. NRC Regulatory Guide 1.106, Thermal Overload Protection for Electric Motors on Motor Valves, Revision 1, March 1977, U.S. Nuclear Regulatory Commission.

18B. NRC Regulatory Guide 1.108, Periodic Testing of Diesel Generator Units used as Onsite Electric Power Systems at Nuclear Power Plants, Revision 1, August 1977, U.S. Nuclear Regulatory Commission.

18C. NRC Regulatory Guide 1.118, Periodic Testing of Electric Power and Protection Systems, June 1976, U.S. Nuclear Regulatory Commission.

18D. NRC Regulatory Guide 1.129, Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Nuclear Power Plants, Revision 1, February 1978, U.S. Nuclear Regulatory Commission.

18E. NRC Regulatory Guide 1.131, Qualification Tests of Electric Cables, Field Splices, and Connections for Light-Water-Cooled Nuclear Power Plants, 8/77 (for comments), U.S. Nuclear Regulatory Commission.

19. IEEE 279-1971, Revision 1, Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations.

20. IEEE 308-1974, Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Systems.

21. IEEE 317-1976, Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations.

22. IEEE 323-1974, Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations.

23. IEEE 334-1974, Standard for Type Tests of Continuous-Duty Class 1E Motors for Nuclear Power Generating Stations.

24. IEEE 336-1971 (ANSI N45.2.4-1972), Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations.

25. IEEE 338-1971, Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems.

26. IEEE 344-1975, Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations.

27. IEEE 352-1972, Guide for General Principles of Reliability Analysis of Nuclear Power Generating Station Protection Systems.

28. IEEE 379-1972, Guide for the Application of the Single- Failure Criterion to Nuclear Power Generating Station Protection Systems.

29. IEEE 382-1972 (ANSI N41.6-1972), Guide for Type Test of Class 1 Electric Valve Operators for Nuclear Power Generating Stations.

30. IEEE 383-1974, Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations.

31. IEEE 384-1974, Trial-Use Standard Criteria for Separation of Class 1E Equipment and Circuits.

32. IEEE 387-1977, Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generation Stations.

33. IEEE 420-1973, Trial-Use Guide for Class 1E Control Switchboards for Nuclear Power Generating Stations.

34. IEEE 422-1973, (draft 3), Guide for the Design and Installation of Cable Systems in Power Generating Stations.

35. IEEE 450-1995, IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead Acid Batteries for Stationary Applications.

36. IEEE 494-1974, Standard Method for Identification of Documents Related to Class 1E Equipment for Nuclear Power Generating Stations.

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38. ICEA P-54-440 (NEMA WC-51-1975), Ampacities, Cables in Open-Top Cable Trays, Rev. 2, August, 1979.

39. NEMA VE 1-1971, Cable Tray Systems, National Electrical Manufacturers Association.

40. IEEE 80-1961 (Reaff. 1971), Guide for Safety in AC Substation Grounding.

41. Wyle Laboratories Test Report No. 48037-02, Electrical Raceway Separation Verification Testing for the Texas Utilities Generating Company for use in the Comanche Peak Steam Electric Station Units 1 and 2, February 6, 1986.

42. Wyle Laboratories Test Report No. 48422-1, Cable Separation Test Program for the Texas Utilities Generating Company Comanche Peak Steam Electric Station Units 1 and 2, August 14, 1986.

43. Wyle Laboratories Test Report No. 47906-02, Test Report on Electrical Separation Verification Testing for the Stone & Webster Engineering Corporation for Use In Niagra Mohawk Power Corporation Nine Mile Point Nuclear Station - Unit 2, November 22, 1985, Configuration No.5.

44. Wyle Laboratories Test Report No. 17666-02, Test Report on Electrical Separation Verification Testing for the Stone & Webster Engineering Corporation for Use In Duquesne Light Company's Beaver Valley Power Station - Unit 2, April 19, 1985, Configurations 1, 2, 3, 4 and 6.

45. ASME Boiler and Pressure Vessel Code, Sections II, III, V, and IX.

46. Brown Boveri Electric, Inc., Test Report K-82089-K1, Test Date May 27, 1982.

47. Wyle Laboratories Test Report No. 53575, Test Report on Separation Verification Testing for Bechtel Energy Corporation for Houston Lighting and Power's South Texas Project, Configuration #1, Test #2.

48. Letter NS-CE-604, dated March 31, 1975, C. Eicheldinger (Westinghouse) to the Secretary of the Nuclear Regulatory Commission.

TABLE 8.3-1
LOADING REQUIREMENTS FOR LOSS-OF-COOLANT ACCIDENT COINCIDENT WITH LOSS OF OFFSITE POWER
(Sheet 1 of 10)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER SIAS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD (B)	TIME TO STOP
CENTRIFUGAL CHARGING PUMP						
TBX-CSAPCH-02 (TBX-CSAPCH-01)	600	YES	10	1	(a)(25)	(4)
MOTOR-OPERATED VALVES						
VARIOUS (VARIOUS)	---	NO	10 (14)	AS REQ'D	(3)	(6)
DIESEL OIL DAY TANK AREA FAN						
CP1-VAFNCB-05 (CP1-VAFNCB-04)	1.5	NO	10 (14)	1	(d)	(4)
DIESEL GENERATOR ROOM FANS						
CP1-VAFNAV-29, 30, 31, 32 (CP1-VAFNAV-25, 26, 27, 28)	40	NO	10 (14)	4	(d)	(4)
DIESEL GENERATOR FUEL OIL TRANSFER PUMP						
CP1-DOAPFT-03, 04 (CP1-DOAPFT-01, 02)	3	NO	10 (10)	2	(d)	(6)
SAFEGUARDS BUILDING FLOOR DRAIN SUMP PUMP						
CP1-WPAPSS-01, 02 (CP1-WPAPSS-03, 04)	5	NO	10 (10)	2	(b)	(6)
CONTROL ROOM PRESSURIZATION FAN (2)						
CPX-VAFNCB-06 (CPX-VAFNCB-05)	5	NO	10 (14) (15)	1	(d)	(5)
CONTROL ROOM EMERGENCY PRESSURIZATION HEATER (2)						
CPX-VAFUPK-22 (CPX-VAFUPK-21)	10 KW	NO	10 (10) (14) (15)	1	(d)	(5)

TABLE 8.3-1
LOADING REQUIREMENTS FOR LOSS-OF-COOLANT ACCIDENT COINCIDENT WITH LOSS OF OFFSITE POWER
(Sheet 2 of 10)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER SIAS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD (B)	TIME TO STOP
CR. RADIATION MONITOR SAMPLE PUMP TRANSFORMER (2)						
CPX-RMTRET-04 (03)	2.070	NO	10 (14)	1	(d)	(4)
UPS ROOM FAN COIL UNIT						
CP1-VAAUPR-02 (CP1-VAAUPR-01)	5	NO	10 (14)	1	(d)	(4)
CONTROL ROOM EMERGENCY FILTRATION FAN						
CPX-VAFNCB-24 (2) (CPX-VAFNCB-23)	30	NO	10 (14) (15)	1	(b)	(5)
CENTRIFUGAL CHARGING PUMP ROOM FAN COOLER						
CP1-VAAUSE-04 (CP1-VAAUSE-03)	3	NO	10 (10)	1	(d)	(4)
BATTERY ROOM EXHAUST FANS						
CP1-VAFNID-09, 10 (CP1-VAFNID-07, 08)	1.5	NO	10 (14)	2	(d)	(4)
LIGHTING TRANSFORMERS						
LIGHTING - TRAIN B (LIGHTING - TRAIN A)	450 KVA	NO	10 (14)	---	(d)	(4)
BATTERY CHARGERS						
CP1-EPBCED-02, 04, 06, 08 (CP1-EPBCED-01, 03, 05, 07)	300 ADC	NO	10 (14)	2	(d)	(4)

TABLE 8.3-1
LOADING REQUIREMENTS FOR LOSS-OF-COOLANT ACCIDENT COINCIDENT WITH LOSS OF OFFSITE POWER
(Sheet 3 of 10)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER SIAS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD (B)	TIME TO STOP
UPS BYPASS TRANSFORMER						
CP1-ECTRET-02 LOAD INCLUDES X-RE-5895B (CP1-ECTRET-01) LOAD INCLUDES X-RE-5896A	25 KVA	NO	10 (14)	1	(d)	(4)
AUXILIARY BUILDING REGULATING TRANSFORMER						
CPX-EPTRNT-43 (2) (CPX-EPTRNT-42)	45 KVA	NO	10 (14)	1	(d)	(4)
REGULATING TRANSFORMER - ALT. SHUTDOWN						
---NONE--- (CP1-EPTRNT-28)	--- 5 KVA	--- NO	--- 10 (14)	--- 1 (TRAIN A ONLY)	--- (d)	--- (4)
SAFEGUARDS BUILDING TRANSFORMER						
CP1-EPTRET-06 (CP1-EPTRET-05)	45 KVA	NO	10 (14)	1	(d)	(4)
SERVICE WATER INTAKE STRUCTURE VENTILATION EXHAUST FAN (24)						
CPX-VAFNWV-08, 09 (CPX-VAFNWV-06, 07)	3	NO	10 (10)	2	(d)	(5)
REGULATING TRANSFORMER						
CPX-EPTRNT-45 (CPX-EPTRNT-44)	30 KVA	NO	10 (14)	1	(d)	(4)
HIGH PRESSURE CHEMICAL FEED ROOM EXHAUST FAN						
CP1-VAFNCB-09 (NONE)	3 ---	NO ---	10 (10) ---	1 --- (TRAIN B ONLY)	(d) ---	(5) ---

TABLE 8.3-1
LOADING REQUIREMENTS FOR LOSS-OF-COOLANT ACCIDENT COINCIDENT WITH LOSS OF OFFSITE POWER
(Sheet 4 of 10)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER SIAS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD (B)	TIME TO STOP
HIGH PRESSURE CHEMICAL FEED ROOM SUPPLY FAN						
CP1-VAFNCB-08	3	NO	10 (10)	1	(d)	(5)
(NONE)	---	---	---	--- (TRAIN B ONLY)	---	---
BATTERY ROOM 117 AND 124 UNIT HEATER						
CP1-VAHEUH-02 (CP1-VAHEUH-03)	25 KW	NO	10 (10)	1	(d)	(5)
BORIC ACID TRANSFER PUMP						
TBX-CASPBA-02 (TBX-CASPBA-01)	20.78	NO	10 (10)	1	(b)	(4)
SAFETY INJECTION PUMP						
TBX-SIAPSI-02 (TBX-SIAPSI-01)	450	YES	15	1	(a) (25)	(4)
CHILLED WATER RECIRCULATING PUMP						
CP1-CHAPCP-06 (CP1-CHAPCP-05)	25	YES	15	1	(d)	(4)
SAFETY INJECTION PUMP ROOM FAN						
CP1-VAAUSE-06 (CP1-VAAUSE-05)	3	NO	15 (10)	1	(d)	(4)
RESIDUAL HEAT REMOVAL PUMP						
TBX-RHAPRH-02 (TBX-RHAPRH-01)	450	YES	20	1	(a) (25)	(4)
RESIDUAL HEAT REMOVAL PUMP ROOM FAN						
CP1-VAAUSE-02 (CP1-VAAUSE-01)	3	NO	20 (10)	1	(d)	(4)

TABLE 8.3-1
LOADING REQUIREMENTS FOR LOSS-OF-COOLANT ACCIDENT COINCIDENT WITH LOSS OF OFFSITE POWER
(Sheet 5 of 10)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER SIAS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD (B)	TIME TO STOP
CONTAINMENT SPRAY PUMP						
CP1-CTAPCS-02, 04 (CP1-CTAPCS-01, 03)	700	YES	25	2	(c) (25)	(4)
CONTAINMENT SPRAY PUMP ROOM FAN						
CP1-VAAUSE-12, 14 (CP1-VAAUSE-11, 13)	3	NO	25 (10)	2	(d)	(4)
COMPONENT COOLING WATER PUMP						
CP1-CCAPCC-02 (CP1-CCAPCC-01)	1000	YES	30	1	(c) (25)	(4)
COMPONENT COOLING WATER PUMP ROOM FAN COOLER						
CP1-VAAUSE-10 (CP1-VAAUSE-09)	3	NO	30 (10)	1	(d)	(4)
STATION SERVICE WATER PUMP						
CP1-SWAPSW-02 (CP1-SWAPSW-01)	900	YES	35	1	(c) (25)	(4)
AUXILIARY FEEDWATER PUMP						
CP1-AFAPMD-02 (CP1-AFAPMD-01)	700	YES	40	1	(c) (25)	(4)
MOTOR DRIVEN AFW PUMP ROOM FAN						
CP1-VAAUSE-08 (CP1-VAAUSE-07)	3	NO	40 (10)	1	(d)	(4)
PRIMARY PLANT VENT EXHAUST FAN (2)						
CPX-VAFNCB-08, -22 (CPX-VAFNCB-07, -21)	60	YES	40	2	(d)	(5)

TABLE 8.3-1
LOADING REQUIREMENTS FOR LOSS-OF-COOLANT ACCIDENT COINCIDENT WITH LOSS OF OFFSITE POWER
(Sheet 6 of 10)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER SIAS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD (B)	TIME TO STOP
PRIMARY PLANT ESF HEATER (2)						
CPX-VAFUPK-02, -16 (CPX-VAFUPK-01, -15)	100 KW	NO	40 (10)	2	(d)	(5)
HVAC CENTRIFUGAL WATER CHILLER						
CP1-CHCICE-06 (CP1-CHCICE-05)	154	YES	75	1	(d)	(5)
UPS AND DISTRIBUTION ROOM A/C UNIT (2)						
CPX-VAACUP-02 (CPX-VAACUP-01)	65.7 KVA	YES	90	1	(d)	(5)
UPS AND DISTRIBUTION ROOM BOOSTER RETURN FAN (2)						
CPX-VAFNAV-43 (CPX-VAFNAV-42)	20	NO	90 (10)	1	(b)	(5)
CONTROL ROOM A/C UNIT (2)						
CPX-VAACCR-03, 04 (CPX-VAACCR-01, 02)	232.6 KVA	YES	90	2 (18)	(d)	(5)
CONTROL ROOM A/C HEATER (2)						
CPX-VAACCR-03, 04 (CPX-VAACCR-01, 02)	30 KW	NO	90 (10)	2 (18)	(d)	(5)
ELECTRICAL AREA FAN						
CP1-VAAUSE-15, 16 (CP1-VAAUSE-17, 18)	5	YES	90	2	(d)	(4)
SPENT FUEL POOL HX AND PUMP ROOM FAN COOLER (2)						
CPX-VAAUSE-02 (CPX-VAAUSE-01)	3	NO	120 (9)	1	(d)	(4)

TABLE 8.3-1
LOADING REQUIREMENTS FOR LOSS-OF-COOLANT ACCIDENT COINCIDENT WITH LOSS OF OFFSITE POWER
(Sheet 7 of 10)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER SIAS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD (B)	TIME TO STOP
SPENT FUEL POOL COOLING WATER PUMP (2)						
CPX-SFAPSF-02 (CPX-SFAPSF-01)	250	NO	120 (9)	1	(b)	(4)
REACTOR MAKE-UP WATER PUMP (2)						
CPX-DDAPRM-01 (CP1-DDAPRM-01)	40	NO	120 (11)	1	(b)	(4)
DG AIR COMPRESSOR						
CP1-MECAED-03, 04 (CP1-MECAED-01, 02)	30	NO	120 (10) (16)	1	(d)	(5)
CONTROL ROOM MAKE-UP SUPPLY FAN (2)						
CPX-VAFNAV-38 (CPX-VAFNAV-37)	2	NO	AS REQ'D (11) (16)	1	(b)	(5)
CONTROL ROOM EXHAUST FAN (2)						
CPX-VAFNID-02 (CPX-VAFNID-01)	5	NO	AS REQ'D (11) (16)	1	(d)	(5)
CONTROL ROOM KIT/TOILET EXHAUST FAN (2)						
CPX-VAFNID-04 (CPX-VAFNID-03)	1.5	NO	AS REQ'D (11) (16)	1	(d)	(5)

SUMMARY:

Total demand KW for loss of coolant accident coincident with loss of offsite power is less than 6300 KW. (Unit 1 Train A or B, Unit 2 Train A or B).

TABLE 8.3-1
LOADING REQUIREMENTS FOR LOSS-OF-COOLANT ACCIDENT COINCIDENT WITH LOSS OF OFFSITE POWER
(Sheet 8 of 10)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER SIAS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD (B)	TIME TO STOP

GENERAL NOTES:

* Where “Pump (Fan)” components are listed, it is understood that the pump (fan) motor is the actual electrical load component.

(A) Train B shown, components powered by Train ‘A’ are shown in parenthesis.

(B) Letters indicated in the “Basis for “KW” column denote the following:

- (a) Pump Runout Condition
- (b) Rated BHP
- (c) Based on Actual Demand
- (d) Nameplate Rating
- (e) Since the MOVs operate intermittently only, this load is not reflected in the running and continuous loading of the D-G. However, all MOVs that may start during diesel generator sequencing and have an auto function to close or open are conservatively assumed to start at the first load step. In addition, 10% of the combined starting load of these MOVs is assumed to occur at each subsequent load step.

(C) Auto sequencer start: “YES” indicates a direct start signal from the sequencer contacts for the step noted in the “START TIME AFTER SIAS” column. “NO” indicates that there is no direct sequencer signal and that the start time is clarified by a note in the “START TIME AFTER SIAS” column.

SPECIFIC NOTES:

1. Maximum closing time to close D-G circuit breaker is 10 seconds after the receipt of start signal including D-G to come up to rated speed and voltage. The “10 seconds” delay indicated in the table is coincident with the D-G circuit breaker closing and step 1 of the sequencer. Step 1 of the sequencer can be delayed by one second when loads are energized from an offsite power source. There is no time delay interposed for non-sequenced loads (Note 14) when the loads are energized from an offsite power source. See Section 8.3.1.1.5.3.
2. Equipment is shared between two units.
3. Not used.
4. Manually stopped.
5. Stops automatically with assigned diesel or pump, temperature, pressure, level, etc.
6. Motor stops automatically when valve action is completed, or receives signal to stop (e.g., sump pump stops on low water level).

TABLE 8.3-1
LOADING REQUIREMENTS FOR LOSS-OF-COOLANT ACCIDENT COINCIDENT WITH LOSS OF OFFSITE POWER
(Sheet 9 of 10)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER SIAS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD (B)	TIME TO STOP

7. For other DBAs which are mitigated by the SIAS such as a Main Steam Line Break accident, automatic loading sequence is same as Loss-of-Coolant Accident condition. See Attachment 3 for other DBAs where loss of offsite power is mitigated by the BOS.
8. For Feedwater Linebreak DBAs, the EDG may be initially started by LOOP and loaded by BOS. (The loss of generation, caused by turbine trip as a result of FWLB, is assumed to initiate a loss of offsite power.) After the initiation of the accident a Safety Injection Actuation Signal (SIAS) is generated based on plant parameter conditions. This (SIAS) initiates the SI Sequencer (SIS). All loads not sequenced by BOS which are required for FWLB are sequenced by SIS. Some non-Class 1E loads are isolated by the SIAS. Thus after the initiation of SIAS only loads also required to be sequenced by SIS remain loaded on the DG. The SIS will send signals to all sequenced loads, the loads already running will keep running and the loads not running will be started. This loading by SIS will result in the final EDG load to be bounded by that represented in the LOCA loading table. The EDG loading calculations are required to evaluate the acceptability of EDG capability to start SIS step loads not running during BOS.
9. As required following diesel loading sequence. Indicated times are estimates and do not restrict plant operation based upon diesel generator loading.
10. Starts automatically with assigned load or upon temperature, pressure, level switch signal, etc.
11. Manually started as required.
12. Not used.
13. Not used.
14. Load is automatically energized as the voltage is restored to the ESF Buses. This load therefore, is not considered a sequenced load.
15. The CREFS is started in the event of a LOCA. If a loss of offsite power occurs, the components will load when power is restored to the bus.
16. Times shown are minimum start times. The SIAS must be reset prior to component start.
17. Not Used.
18. The Control Room HVAC (CRAC) A/C Units and A/C Heaters are mutually exclusive loads. The larger load (CRAC Unit) is considered in EDG loading.
19. Thru 23. Not Used.
24. Components CPX-VAFNWV-08 & 09 are fed from Unit 1, Train B. Components CPX-VAFNWV-06 & 07 are fed from Unit 1, Train A. Components CPX-VAFNWV-04 & 05 are fed from Unit 2, Train B. Components CPX-VAFNWV-02 & 03 are fed from Unit 2, Train A.
25. Calculated pump runout condition or actual load demand.

TABLE 8.3-1
LOADING REQUIREMENTS FOR LOSS-OF-COOLANT ACCIDENT COINCIDENT WITH LOSS OF OFFSITE POWER
(Sheet 10 of 10)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER SIAS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD (B)	TIME TO STOP

Abbreviations:

Component cooling water pump (CCWP); safety injection system (SIS); residual heat removal (RHR); heating, ventilating and air conditioning (HVAC); balance of plant (BOP); Nuclear Safety Related (NSR); air conditioning (A/C).

TABLE 8.3-1A
ALL SHEETS HAVE BEEN DELETED

TABLE 8.3-1B
ALL SHEETS HAVE BEEN DELETED

TABLE 8.3-1C
OUT OF TOLERANCE VOLTAGE VALUES (CLASS 1E 6.9KV SWITCHGEAR AND 480 VOLT LOAD CENTERS)

BUS	NOMINAL VOLTAGE	MINIMUM ALLOWABLE VOLTAGE	MAXIMUM ALLOWABLE VOLTAGE
6.9KV Switchgear 1EA1, 2EA1, 1EA2, 2EA2	6900	5965	7260
480V Switchgear 1EB1, 2EB1, 1EB3, 2EB3, 1EB2, 2EB2, 1EB4, 2EB4	480	435	510

TABLE 8.3-1D
THIS TABLE HAS BEEN DELETED

TABLE 8.3-2
EMERGENCY ELECTRICAL LOADING REQUIREMENTS FOR LOSS OF OFFSITE POWER (BLACKOUT) CONDITIONS
(Sheet 1 of 13)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER BOS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD.(B)	TIME TO STOP
CENTRIFUGAL CHARGING PUMP						
TBX-CSAPCH-02 (TBX-CSAPCH-01)	600	YES	10	1	(a)(25)	(4)
MOTOR-OPERATED VALVES						
VARIOUS (VARIOUS)	---	NO	10 (14)	AS REQ'D	(3)	(6)
DIESEL OIL DAY TANK AREA FAN						
CP1-VAFNCB-05 (CP1-VAFNCB-04)	1.5	NO	10 (14)	1	(d)	(4)
DIESEL GENERATOR ROOM FANS						
CP1-VAFNAV-29, 30, 31, 32 (CP1-VAFNAV-25, 26, 27, 28)	40	NO	10 (14)	4	(d)	(4)
DIESEL GENERATOR FUEL OIL TRANSFER PUMP						
CP1-DOAPFT-03, 04 (CP1-DOAPFT-01, 02)	3	NO	10 (10)	2	(d)	(5)
SAFEGUARDS BUILDING FLOOR DRAIN SUMP PUMP						
CP1-WPAPSS-01, 02 (CP1-WPAPSS-03, 04)	5	NO	10 (10)	2	(b)	(6)
CHILLED WATER RECIRCULATION PUMP						
CP1-CHAPCP-06 (CP1-CHAPCP-05)	25	NO	10 (14)	1	(d)	(4)

TABLE 8.3-2
EMERGENCY ELECTRICAL LOADING REQUIREMENTS FOR LOSS OF OFFSITE POWER (BLACKOUT) CONDITIONS
(Sheet 2 of 13)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER BOS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD.(B)	TIME TO STOP
CONTROL ROOM PRESSURIZATION FAN (2)						
CPX-VAFNCB-06 (CPX-VAFNCB-05)	5	NO	10 (14)	1	(d)	(5)
CONTROL ROOM EMERGENCY PRESSURIZATION HEATER (2)						
CPX-VAFUPK-22 (CPX-VAFUPK-21)	10 KW	NO	10 (10)	1	(d)	(5)
CONTROL ROOM EMERGENCY FILTRATION FAN (2)						
CPX-VAFNCB-24 (CPX-VAFNCB-23)	30	NO	10 (14)	1	(b)	(5)
FUEL OIL BOOSTER PUMP						
CP1-DOAPBP-02 (CP1-DOAPBP-01)	3	NO	10 (10)	1	(d)	(4)
UPS ROOM FAN COIL UNIT						
CP1-VAAUPR-02 (CP1-VAAUPR-01)	5	NO	10 (14)	1	(d)	(4)
FUEL OIL DRIP RETURN PUMP						
CP1-DOAPDW-02 (CP1-DOAPDW-01)	1	NO	10 (10)	1	(d)	(4)
CENTRIFUGAL CHARGING PUMP ROOM FAN COOLER						
CP1-VAAUSE-04 (CP1-VAAUSE-03)	3	NO	10 (10)	1	(d)	(4)
BATTERY ROOM EXHAUST FANS						
CP1-VAFNID-09, 10, 12 (CP1-VAFNID-07, 08, 11)	1.5	NO	10 (14)	3	(d)	(4)

TABLE 8.3-2
EMERGENCY ELECTRICAL LOADING REQUIREMENTS FOR LOSS OF OFFSITE POWER (BLACKOUT) CONDITIONS
(Sheet 3 of 13)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER BOS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD.(B)	TIME TO STOP
LIGHTING TRANSFORMERS						
LIGHTING - TRAIN B (LIGHTING - TRAIN A)	495 KVA	NO	10 (14)	---	(d)	(4)
BATTERY CHARGERS						
CP1-EPBCED-02, 04, 06, 08 (CP1-EPBCED-01, 03, 05, 07)	300 ADC	NO	10 (14)	2	(d)	(4)
BATTERY CHARGER						
CP1-EPBCND-02, 04 (NONE)	200 ADC ---	NO ---	10 (14) ---	1 (TRAIN B ONLY) ---	(d) ---	(4) ---
CONTROL ROOM RADIATION MONITOR SAMPLE PUMP TRANSFORMER (2)						
CPX-RMTRET-04(03)	1.5	NO	10 (14)	1	(d)	(4)
VENTILATION STACK RADIATION MONITOR SYSTEM SAMPLE PUMP (2)						
X-RE-5567B (X-RE-5567A)	1.5	NO	10 (14)	1	(d)	(4)
CONTAINMENT AIR RADIATION MONITOR SAMPLE PUMP						
1-RE-5502-03-66 (NONE)	1.5 ---	NO ---	10 (14) ---	1 (TRAIN B ONLY) ---	(d) ---	(4) ---
SUPS BYPASS TRANSFORMER						
CP1-ECTRET-02 LOAD INCLUDES X-RE-5895B (CP1-ECTRET-01) LOAD INCLUDES X-RE-5896A	25 KVA	NO	10 (14)	1	(d)	(4)

TABLE 8.3-2
EMERGENCY ELECTRICAL LOADING REQUIREMENTS FOR LOSS OF OFFSITE POWER (BLACKOUT) CONDITIONS
(Sheet 4 of 13)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER BOS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD.(B)	TIME TO STOP
CONTROL BUILDING BYPASS TRANSFORMER						
NONE	---	---	---	---	---	---
(CP1-EPTRMT-12)	10 KVA	NO	10 (14)	1 (TRAIN A ONLY)	(d)	(4)
AUXILIARY BUILDING REGULATING TRANSFORMER						
CPX-EPTRNT-43 (CPX-EPTRNT-42)	45 KVA	NO	10 (14)	1	(d)	(4)
REGULATING TRANSFORMER - ALT. SHUTDOWN						
NONE	---	---	---	---	---	---
(CP1-EPTRNT-28)	5 KVA	NO	10 (14)	1 (TRAIN A ONLY)	(d)	(4)
SAFEGUARDS BUILDING TRANSFORMER						
CP1-EPTRET-06 (CP1-EPTRET-05)	45 KVA	NO	10 (14)	1	(d)	(4)
REGULATING TRANSFORMER						
CPX-EPTRNT-45 (CPX-EPTRNT-44)	30 KVA	NO	10 (14)	1	(d)	(4)
HIGH PRESSURE CHEMICAL FEED ROOM EXHAUST FAN						
CP1-VAFNCB-09	3	NO	10 (10)	1 (TRAIN B	(d)	(5)
(NONE)	---	---	---	--- ONLY)	---	---
HIGH PRESSURE CHEMICAL FEED ROOM SUPPLY FAN						
CP1-VAFNCB-08	3	NO	10 (10)	1 (TRAIN B	(d)	(5)
(NONE)	---	---	---	--- ONLY)	---	---

TABLE 8.3-2
EMERGENCY ELECTRICAL LOADING REQUIREMENTS FOR LOSS OF OFFSITE POWER (BLACKOUT) CONDITIONS
(Sheet 5 of 13)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER BOS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD.(B)	TIME TO STOP
BATTERY ROOM 117 AND 124 UNIT HEATER						
CP1-VAHEUH-02 (CP1-VAHEUH-03)	25 KW	NO	10 (10)	1	(d)	(5)
BORIC ACID TRANSFER PUMP						
TBX-CASPBA-02 (TBX-CASPBA-01)	20.78	NO	10 (10)	1	(b)	(4)
ROOM ADJACENT TO REACTOR MAKEUP WATER STORAGE TANK HEATER						
CP1-VAEHUH-28 (CP1-VAEHUH-25)	10 KW	NO	10 (14)	1	(d)	(5)
ROOM ADJACENT TO COND. WATER STORAGE TANK HEATER						
CP1-VAEHUH-29 (CP1-VAEHUH-26)	10 KW	NO	10 (14)	1	(d)	(5)
ROOM ADJACENT TO REFUELING WATER STORAGE TANK HEATER						
CP1-VAEHUH-30 (CP1-VAEHUH-27)	7.5 KW	NO	10 (14)	1	(d)	(5)
AIR DRYER CONTROL PANEL FDR						
CP1-CIDYIA-02 (CP1-CIDYIA-01)	18.3 KW	NO	10 (14)	1	(d)	(4)
SERVICE WATER PUMPHOUSE VENTILATION (24) EXHAUST FAN						
CPX-VAFNWV-08, 09 (CPX-VAFNWV-06, 07)	3	NO	10 (10)	2	(d)	(5)

TABLE 8.3-2
EMERGENCY ELECTRICAL LOADING REQUIREMENTS FOR LOSS OF OFFSITE POWER (BLACKOUT) CONDITIONS
(Sheet 6 of 13)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER BOS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD.(B)	TIME TO STOP
COMPONENT COOLING WATER PUMP FAN COOLER						
CP1-VAAUSE-10 (CP1-VAAUSE-09)	3	NO	30 (10)	1	(d)	(4)
COMPONENT COOLING WATER PUMP						
CP1-CCAPCC-02 (CP1-CCAPCC-01)	1000	YES	30	1	(c) (25)	(4)
CRDM VENT FAN						
CP1-VAFNCB-02 (CP1-VAFNCB-01)	125	YES	30	1	(b)	(4)
STATION SERVICE WATER PUMP						
CP1-SWAPSW-02 (CP1-SWAPSW-01)	900	YES	35	1	(c) (25)	(4)
AUXILIARY FEEDWATER PUMP						
CP1-AFAPMD-02 (CP1-AFAPMD-01)	700	YES	40	1	(c) (22)(25)	(4)
MOTOR DRIVEN AFW PP ROOM FAN						
CP1-VAAUSE-08 (CP1-VAAUSE-07)	3	NO	40 (10)	1	(d)	(4)
CONTAINMENT RECIRCULATION FAN						
CP1-VAFNAV-02, 04 (CP1-VAFNAV-01, 03)	125	YES	50	2	(b)	(4)
NEUTRON DETECTOR WELL FAN						
CP1-VAFNAV-10 (CP1-VAFNAV-09)	40	YES	50	1	(b)	(4)

TABLE 8.3-2
EMERGENCY ELECTRICAL LOADING REQUIREMENTS FOR LOSS OF OFFSITE POWER (BLACKOUT) CONDITIONS
(Sheet 7 of 13)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER BOS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD.(B)	TIME TO STOP
VENT CHILLED WATER PUMP						
CPX-CHAPCP-02, 04 (CPX-CHAPCP-01, 03)	125	YES	60	2	(d)	(4)
AUXILIARY BUILDING VENT EQUIPMENT ROOM EXHAUST FAN						
CPX-VAFNAV-28 (CPX-VAFNAV-27)	40	YES	60	1	(b)	(4)
HVAC CENTRIFUGAL WATER CHILLER						
CP1-CHCICE-06 (CP1-CHCICE-05)	154	YES	75	1	(d)	(4)
HVAC CENTRIFUGAL WATER CHILLER (2), (2A)						
CPX-CHCICE-02, (CPX-CHCICE-01)	670	YES	85 (20)	1	(c)	(4)
HVAC CENTRIFUGAL WATER CHILLER OIL PUMP (2)						
CPX-CHCICE-02B, 04B (CPX-CHCICE-01B, 03B)	0.25	NO	85 (10)(20)	2	(d)	(5)
UPS AND DISTRIBUTION ROOM A/C UNIT (2)						
CPX-VAACUP-02 (CPX-VAACUP-01)	65.7 KVA	YES	90	1	(d)	(4)
UPS AND DISTRIBUTION ROOM BOOSTER RETURN FAN (2)						
CPX-VAFNAV-43 (CPX-VAFNAV-42)	20	NO	90 (10)	1	(b)	(5)
CONTROL ROOM A/C HEATER (2)						
CPX-VAACCR-03, 04 (CPX-VAACCR-01, 02)	30 KW	NO	90 (10)	2 (18)	(d)	(5)

TABLE 8.3-2
EMERGENCY ELECTRICAL LOADING REQUIREMENTS FOR LOSS OF OFFSITE POWER (BLACKOUT) CONDITIONS
(Sheet 8 of 13)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER BOS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD.(B)	TIME TO STOP
CONTROL ROOM A/C UNIT (2)						
CPX-VAACCR-03, 04 (CPX-VAACCR-01, 02)	232.6 KVA	YES	90	2 (18)	(d)	(5)
ELECTRICAL AREA FAN						
CP1-VAAUSE-15, 16 (CP1-VAAUSE-17, 18)	5	YES	90	2	(d)	(4)
INSTRUMENT AIR COMPRESSOR						
CP1-CICACO-02 (CP1-CICACO-01)	200	NO	90 (10)	1	(d)	(4)
DG AIR COMPRESSOR						
CP1-MECAED-03, 04 (CP1-MECAED-01, 02)	30	NO	120 (10)	1	(d)	(4)
AUXILIARY LUBE OIL PP						
CP1-MEAPLO-04 (CP1-MEAPLO-02)	60	NO	120 (11)	1	(23)	(23)
COMPRESSOR AFTERCOOLER						
CP1-MECAAC-03, 04 (CP1-MECAAC-01, 02)	1	NO	120 (11)	1	(d)	(5)
AUXILIARY JACKET WTR PP						
CP1-MEAPJW-04 (CP1-MEAPJW-02)	75	NO	120 (11)(23)	1	(d)	(4)
PRIMARY PLANT VENT EXHAUST FAN						
CPX-VAFNCB-10,12,14,16,18,20 (CPX-VAFNCB-09,11,13,15,17,19)	60	NO	120 (11)	2 (MAX)	(d)	(5)

TABLE 8.3-2
EMERGENCY ELECTRICAL LOADING REQUIREMENTS FOR LOSS OF OFFSITE POWER (BLACKOUT) CONDITIONS
(Sheet 9 of 13)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER BOS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD.(B)	TIME TO STOP
POSITIVE DISPLACEMENT CHARGING PUMP (16)						
NONE (TBX-CSAPPD-01)	---- 200	---- NO	---- 120 (11)	---- 1 (TRAIN A ONLY)	---- (16)	---- (4)
POSITIVE DISPLACEMENT CHARGING PUMP FAN COOLER						
NONE (CP1-VAFNCB-03)	---- 1.5	---- NO	---- 120(11)(17)	---- 1 (TRAIN A ONLY)	---- (16)	---- (4)
REACTOR MAKE-UP WATER PUMP						
CPX-DDAPRM-01 (CP1-DDAPRM-01)	40	NO	120 (11)	1	(b)	(5)
SPENT FUEL POOL COOLING WATER PUMP (2)						
CPX-SFAPSF-02 (CPX-SFAPSF-01)	250	NO	30 MIN (9)	1	(b)	(4)
SPENT FUEL POOL HX AND PUMP ROOM FAN COOLER (2)						
CPX-VAAUSE-02 (CPX-VAAUSE-01)	3	NO	30 MIN (9)	1	(d)	(4)
REGULATING TRANSFORMER FOR PRESSURIZER HEATERS (19)						
CP1-EPTRNT-06, 08 (CP1-EPTRNT-05, 07)	485 KW	NO	60 MIN (9)	1	(c)	(4)
RESIDUAL HEAT REMOVAL PUMP						
TBX-RHAPRH-02 (TBX-RHAPRH-01)	45O	NO	4 HOURS (9)	1	(a) (25)	(4)

TABLE 8.3-2
EMERGENCY ELECTRICAL LOADING REQUIREMENTS FOR LOSS OF OFFSITE POWER (BLACKOUT) CONDITIONS
(Sheet 10 of 13)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER BOS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD.(B)	TIME TO STOP
RESIDUAL HEAT REMOVAL PUMP ROOM FAN						
CP1-VAAUSE-02 (CP1-VAAUSE-01)	3	NO	4 HOURS (9)	1	(d)	(4)
CONTROL ROOM MAKE-UP SUPPLY FAN (2)						
CPX-VAFNAV-38 (CPX-VAFNAV-37)	2	NO	AS REQ'D (11)	1	(b)	(5)
CONTROL ROOM EXHAUST FAN (2)						
CPX-VAFNID-02 (CPX-VAFNID-01)	5	NO	AS REQ'D (11)	1	(d)	(5)
CONTROL ROOM KIT/TOILET EXHAUST FAN (2)						
CPX-VAFNID-04 (CPX-VAFNID-03)	1.5	NO	AS REQ'D (11)	1	(d)	(5)
SERVICE WATER SCREEN WASH PUMP						
CPX-SWAPTS-02 (CPX-SWAPTS-01)	15	NO	AS REQ'D (11)	1	(d)	(5)
SERVICE WATER TRAVELING SCREEN						
CPX-SWTSTS-02 (CPX-SWTSTS-01)	1.5	NO	AS REQ'D (10)	1	(d)	(5)

SUMMARY:

Total demand KW for loss of offsite power is less than 6300 KW (Unit 1 Train A or B, Unit 2 Train A or B).

TABLE 8.3-2
EMERGENCY ELECTRICAL LOADING REQUIREMENTS FOR LOSS OF OFFSITE POWER (BLACKOUT) CONDITIONS
(Sheet 11 of 13)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER BOS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD.(B)	TIME TO STOP

GENERAL NOTES:

* Where “Pump (Fan)” components are listed, it is understood that the pump (fan) motor is the actual electrical load component.

(A) Components powered by Train ‘A’ are shown in parenthesis.

(B) Letters indicated in the “Basis for “KW” column denote the following:

(a) Pump Runout Condition

(b) Rated BHP

(c) Based on Actual Demand

(d) Nameplate Rating

(e) Since the MOVs operate intermittently only, this load is not reflected in the running and continuous loading of the D-G. However, all MOVs that may start during diesel generator sequencing and have an auto function to close or open are conservatively assumed to start at the first load step. In addition 10% of the combined starting load of these MOVs is assumed to occur at each subsequent load step.

(C) Auto sequence start: “YES” indicated a direct start signal from the sequencer contacts for the step noted in the “START TIME AFTER BOS” column. “NO” indicates that there is no direct sequencer signal and that the start time is specified by a note in the “START TIME AFTER BOS”.

(D) Shared components prefixed with CPX.

SPECIFIC NOTES:

1. Maximum closing time to close D-G circuit breaker is 10 seconds after the receipt of start signal including D-G to come up to rated speed and voltage. The “10 seconds” delay indicated in the table is coincident with the D-G circuit breaker closing and step 1 of the sequencer. There is no time delay interposed for non-sequenced loads (Note 14) when the loads are energized from an offsite power source. See Section 8.3.

2. Equipment is shared between two units.

3. The HVAC centrifugal water chiller are powered from the 6.9KV buses: CPX-CHCICE-01 from Unit 1 Train A, CPX-CHCICE-02 from Unit 1 Train B, CPX-CHCICE-03 from Unit 2 Train A, CPX-CHCICE-04 from Unit 2 Train B.

TABLE 8.3-2
EMERGENCY ELECTRICAL LOADING REQUIREMENTS FOR LOSS OF OFFSITE POWER (BLACKOUT) CONDITIONS
(Sheet 12 of 13)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER BOS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD.(B)	TIME TO STOP

4. Manually stopped.
5. Stops automatically with assigned diesel or pump, temperature, pressure, level, etc.
6. Motor stops automatically when valve action is completed, or receives signal to stop (e.g., sump pump stops on low water level).
7. Not Used.
8. For Feedwater Linebreak DBAs, the EDG may be initially started by LOOP and loaded by BOS. (The loss of generation, caused by turbine trip as a result of FWLB, is assumed to initiate a loss of offsite power.) After the initiation of the accident a Safety Injection Actuation Signal (SIAS) is generated based on plant parameter conditions. This (SIAS) initiates the SI Sequencer. All loads not sequenced by BOS which are required for FWLB are sequenced by SIS. Some non-Class 1E loads are isolated by the SIAS. Thus after the initiation of SIAS only loads also required to be sequenced by SIS remain loaded on the DG. The SIS will send signals to all sequenced loads, the loads already running will keep running and the loads not running will be started. This loading by SIS will result in the final EDG load to be bounded by that represented in the LOCA loading table. The EDG loading calculations are required to evaluate the acceptability of EDG capability to start SIS step loads not running during BOS.
9. As required following diesel loading sequence. Indicated times are estimates and do not restrict plant operation based upon diesel generator loading.
10. Starts automatically with assigned load or upon temperature, pressure, level switch signal, etc.
11. Manually started as required.
12. Not used.
13. Not used.
14. Load is automatically energized as the voltage is restored to the ESF Buses. This load therefore, is not considered a sequenced load.
15. Deleted
16. Operates in lieu of the centrifugal charging pump (CCP). The CCP is included in the total continuous load.
17. Operates in association with positive displacement charging pump.
18. The Control Room HVAC (CRAC) A/C units and A/C heaters are mutually exclusive loads. The larger load (CRAC unit) is considered in the EDG loading.

TABLE 8.3-2
EMERGENCY ELECTRICAL LOADING REQUIREMENTS FOR LOSS OF OFFSITE POWER (BLACKOUT) CONDITIONS
(Sheet 13 of 13)

EQUIPMENT DESCRIPTION & TAG NUMBERS* (A)	NAMEPLATE HP (KW/KVA/A IF INDICATED)	AUTO SEQUENCER START (C)	START TIME AFTER BOS (SEC) (1) (8)	NUMBER REQUIRED PER TRAIN	BASIS FOR KW REQD.(B)	TIME TO STOP

19. Four groups of pressurizer heaters are installed. Groups A and B, are 485 KW and Group C and D are 416 KW; any group can be energized manually as required after the loss of power.

20. Start signal is from 85 second step. There may be additional delay due to equipment interlocks.

21. Not used.

22. The basis for the Auxiliary Feedwater Pump required BHP is documented by calculation. During the Loss of Offsite Power event, the BHP requirement for a single pump is not mopre than 750 HP. Actual pump demand decreases as the plant cools down and flow to the steam generators is manually controlled by the control room operator to maintain SG level.

23. Auxiliary Lube Oil Pump is only required if Shaft Driven Pump fails. Mechanical failure of not more than one pump is postulated. To be conservative, Jacket Water Pump (75 HP) loading has been included; hence, no additional loading is required due to Auxiliary Lube Oil Pump (60 HP) failure.

24. Components CPX-VAFNWV-08 & 09 ar fed from Unit 1, Train A. Components CPX-VAFNWV-06 & 07 are fed from Unit 1, Train B. Components CPX-VAFNWV-04 & 05 are fed from Unit 2, Train A. Components CPX-VAFNWV-02 & 03 are fed from Unit 2, Train B.

25. Calculated pump runout condition or actual load demand.

Abbreviations:

Component cooling water pump (CCWP); blackout signal (BOS); residual heat removal (RHR); heating, ventilating, and air conditioning (HVAC); balance of plant (BOP); Nuclear Safety Related (NSR); air conditioning (A/C).

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 1 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
1	138-kV offsite power source	supplies power to startup transformer XST1	fails to provide electrical power to XST1	transmission line fails; opposite end HV circuit breaker opens.	loss of electrical power to transformer XST1	protective relays; annunciation in control room	None: offsite power source (Item 2) or diesel generators are available.
2	345-kV offsite power source	supplies power to startup transformer XST2	fails to provide electrical power to XST2	transmission line fails; circuit breaker in switchyard opens.	loss of electrical power to transformer XST2	protective relays; annunciation in control room	None: offsite power source (Item 1) or diesel generators are available.
3	Startup transformer XST1	supplies power at 6.9 kV to buses 2EA1 and 2EA2 of Unit 2 and is an alternate power source for buses 1EA1 and 1EA2 of Unit 1	fails to deliver power	internal fault; component failure; overheating; fire	loss of power to buses 2EA1 and 2EA2 and loss of alternate power source for buses 1EA1 and 1EA2	protective relays; annunciation in control room	None: offsite power source (Item 2) or diesel generators are available.
3A	15-kV cable	transmits power from XST1 to buses 1EA1 and 1EA2	short circuit; open circuit	mechanical damage; fire	For open circuit: Loss of alternate power to buses 1EA1 and 1EA2 from XST1. For short circuit: Loss of power to buses 2EA1, 2EA2, and loss of alternate power source for buses 1EA1 and 1EA2.	protective relays; annunciation in control room	None: Offsite power source (Item 2) or diesel generators are available.

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 2 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
3B	15-kV cable	transmits power from XST1 to buses 2EA1 and 2EA2	short circuit; open circuit	mechanical damage; fire	For open circuit: Loss of power to buses 2EA1 and 2EA2 from XST1. For short circuit: Loss of power to buses 2EA1, 2EA2, and loss of alternate power source for buses 1EA1 and 1EA2.	protective relays; annunciation in control room	None: offsite power source (Item 2) or diesel generators are available.
4	startup transformer XST2	supplies power at 6.9 kV to buses 1EA1 and 1EA2 of Unit 1 through CPX-EPTSST-02Y; and is an alternate power source for buses 2EA1 and 2EA2 of Unit 2 through CPX-EPTSST-02X	fails to deliver power	internal fault; component failure; overheating; fire	loss of power to buses 1EA1, and 1EA2 and loss of alternate power source for buses 2EA1 and 2EA2	protective relays; annunciation in control room	None: offsite power source (Item 1) or diesel generators are available. Can also realign to spare startup transformer XTS2A (Item 4C).

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 3 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
4A	15-KV cable	transmits power to transfer panel CPX-EPTSST-02Y from XST2	short circuit; open circuit	mechanical damage; fire	For open circuit: Loss of power to buses 1EA1 and 1EA2 from XST2. For short circuit: Loss of power to buses 1EA1, 1EA2 and loss of alternate power source for buses 2EA1 and 2EA2.	Protective relays; annunciation in control room	None: offsite power source (Item 1) or diesel generators are available. Can also realign to spare startup transformer XTS2A (Item 4C).
4B	15-KV cable	Transmits power from transfer panel CPX-EPTSST-02X from XST2	short circuit; open circuit	mechanical damage; fire	For open circuit: Loss of alternate power to buses 2EA1 and 2EA2 from XST2. For short circuit: Loss of power to buses 1EA1, 1EA2 and loss of alternate power source for buses 2EA1 and 2EA2.	protection relays; annunciation in control room	None: offsite power source (Item 1) or diesel generators are available. Can also realign to spare startup transformer XTS2A (Item 4C).
4C	Spare Startup transformer XST2A	Supplies power to 6.9kV to buses 1EA1 and 1EA2 of Unit 1 through CPX-EPTSST-032Y; and is an alternate power source for buses 2EA1 and 2EA2 of Unit 2 through CPX-EPTSST-032X	Fails to deliver power	Internal fault; component failure; oveheating; fire	Loss of power to buses 1EA1 and 1EA2 and loss of alternate power source for buses 2EA1 and 2EA2.	Protective relays; annunciation in the control room	None; offiste power source (Item 1) or diesel generator available. Can also realign to startup transformer XST2 (Item 4).

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 4 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
4D	15-KV Cable	Transmits power to transfer panel CPX-EPTSST-03Y from XST2A	Short circuit; open circuit	Mechanical damage; fire	For open circuit: Loss of power to buses 1EA1 and 1EA2 from XST2A. For short circuit: Loss of power to buses 1EA1, 1EA2 and loss of alternate power source for buses 2EA1 and 2EA2.	Protective relays; annunciation in the control room	None; offsite power source (Item 1) or diesel generators are available. Can also realign to startup transformer XST2 (Item 4).
4E	15-KV Cable	Transmits power to transfer panel CPX-EPTSST-032X from XST2A	Short circuit; open circuit	Mechanical damage; fire	For open circuit: Loss of power to alternate buses 2EA1 and 2EA2 from XST2A. For short circuit: Loss of power to buses 1EA1, 1EA2 and loss of alternate power source for buses 2EA1 and 2EA2.	Protective relays; annunciation in teh control room	None; offiste power source (Item 1) or diesel generators are available. Can also realign to startup transformer XST2 (Item 4).
4F	15-KV Transfer Panel CPX-EPTSST-02X/03X	Transmits power to buses 2EA1 and 2EA2 of Unit 2 from XST2 or XST2A	Short circuit; open circuit	Mechanical damage; fire	For open circuit: Loss of alternate power source to buses 2EA1 and 2EA2. For short circuit: Loss of power to buses 1EA1, 1EA2 and loss of alternate power source for buses 2EA1 and 2EA2.	Protective relays; annunciation in the control room	None; offsite power sources (Item 1) or diesel generators are available.

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 5 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
4G	15-KV Transfer Panel CPX-EPTSST-02Y/03Y	Transmits power to buses 1EA1 and 1EA2 of Unit 2 from XST2 or XST2A	Short circuit; open circuit	Mechanical damage; fire	For open circuit: Loss of power to buses 1EA1 and 1EA2. For short circuit; Loss of power to buses 1EA1, 1EA2 and loss of alternate power source for buses 2EA1 and 2EA2.	Protective relays; annunciation in the contol room	None; offsite power source (Item 1) or diesel generators are available.
4H	15-KV Cable	Transmits power from transfer panel CPX-EPTSST-02Y and 03Y to buses 1EA1 and 1EA2	Short circuit; open circuit	Mechanical damage; fire	For open circuit: Loss of power to buses 1EA1 and 1EA2. For short circuit: Loss of power to buses 1EA1, 1EA2 and loss of alternate power source for buses 2EA1 and 2EA2.	Protective relays; annunciation in the control room	None; offsite power source (Item 1) or diesel generators are available
4I	15-KV Cable	Transmits power from transfer panel CPX-EPTSST-02X and 03Y to buses 2EA1 and 2EA2	Short circuit; open circuit	Mechanical damage; fire	For open circuit: Loss of alternate power source to buses 2EA1 and 2EA2. For short circuit: Loss of power to buses 1EA1, 1EA2 and loss of alternate power source for buses 2EA1 and 2EA2.	Protective relays; annunciation in the control room	None; offsite power source (Item 1) or diesel generators are available.

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 6 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
5	6.9-kV circuit breaker 1EA1-2	protects bus 1EA1	fails to open; fails to close	mechanical failure; stuck contacts; relay failure; control power fails; fire; loss of ventilation	1. Failure to open could cause loss of bus 1EA1 & XFMR XST1 2. Fails to close: power cannot be supplied from XST1	1. Annunciation 2. Periodic testing for operational readiness	None: 1. Redundant equipment is provided on bus 1EA2. 2. Power can be supplied from offsite power source (Item 2) or diesel generator 1EG1.
6	6.9-kV circuit breaker 1EA1-1	protects bus 1EA1	fails to open; fails to close	mechanical failure; stuck contacts; relay failure; control power fails; fire; loss of ventilation	1. Failure to open could cause loss of 1EA1 & XFMRS XST2 and 1^{ST} 2. Fails to close: power cannot be supplied from power source XST2	1. Annunciation 2. Periodic testing for operational readiness	None: 1. Redundant equipment is provided on bus 1EA2. 2. Power can be supplied from offsite power source (Item 1) or diesel generator 1EG1.
7	6.9-kV circuit breaker 1EA2-2	protects bus 1EA2	fails to open; fails to close	mechanical failure; stuck contacts; relay failure; control power fails; fire; loss of ventilation	1. Failure to open could cause 1EA2 & XFMR XST1 2. Fails to close: power cannot be supplied from XST1	1. Annunciation 2. Periodic testing for operational readiness	None: 1. Redundant equipment is provided on bus 1EA1. 2. Power can be supplied 66# from offsite power source (Item 2) or diesel generator 1EG2.

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 7 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
8	6.9-kV circuit breaker 1EA2-1	protects bus 1EA2	fails to open; fails to close	mechanical failure; stuck contacts; relay failure; control power fails; fire; loss of ventilation	1. Failure to open could cause loss of bus 1EA2 & XFMRS XST2 & 1ST 2. Fails to close: power cannot be supplied from power source XST2	1. Annunciation 2. Periodic testing for operational readiness	None: 1. Redundant equipment is provided on bus 1EA1. 2. Power can be supplied from offsite power source (Item 1) or diesel generator 1EG2.
9	Bus 1EA1	distributes electrical power to Train A loads	fails to deliver power	short circuit; overload; fire; loss of ventilation	loss of Train A safety load group	1. protective relays 2. Annunciation in Control Room	None: Redundant Train B from bus 1EA2 available
10	Bus 1EA2	distributes electrical power to Train B loads	fails to deliver power	short circuit overload; fire; loss of ventilation	loss of Train B safety load group	1. protective relays 2. Annunciation in Control Room	None: redundant Train A from from bus 1EA1 available
11	6.9-kV circuit breaker	protects Unit Substation transformer T1EB1	fails to open; fails to close	mechanical failure; stuck contacts; relay failure; control power fails; fire; loss of ventilation	1. Fails to open: back up breaker opens and loss of 1EA1 Bus 2. Fails to close: loss of power to 1EB1	1. protective relays 2. Annunciation redundant load group in Control Room	None: Load supplied by redundant load group provided from bus 1EA2
11A	8-kV cable	connects circuit breaker and transformer T1EB1	short circuit; open circuit	Mechanical damage; fire	loss of power to bus 1EB1	1. protective relays 2. Annunication in Control Room	None: load supplied by redundant load group provided from bus 1EA2

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 8 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
12	6.9-kV circuit breaker	protects unit substation transformer T1EB3	fails to open; fails to close	mechanical failure; stuck contacts; relay failure; control power fails; fire; loss of ventilation	1. Fails to open: back up breaker opens and loss of 1EA1 Bus 2. Fails to close: loss of power to 1EB3	1. protective relays 2. Annunciation in Control Room	None: Load supplied by redundant load group provided from bus 1EA2
12A	8-kV cable	connects circuit breaker and transformer T1EB3	short circuit; open circuit	mechanical damage; fire	loss of power to bus 1EB3	1. protective relays 2. Annunciation in Control Room	None: Load supplied by redundant load group provided from bus 1EA2
13	6.9-kV circuit breaker	Protects Unit substation transformer T1EB2	fails to open; fails to close	Mechanical failure; stuck contacts; relay failure; control power fails; fire; loss of ventilation	1. Fails to open: back up breaker opens and loss of 1EA2 bus 2. Fails to close: loss of power to 1EB2	1. protective relays 2. Annunciation in Control Room	None: Load supplied by redundant load group provided from bus 1EA1
13A	8-kV cable	connects circuit breaker and transformer T1EB2	short circuit; open circuit	mechanical damage; fire	loss of power to bus 1EB2	1. protective relays 2. Annunciation in Control Room	None: Load supplied by redundant load group provided from bus 1EA1
14	6.9-kV circuit breaker	protects Unit substation transformer T1EB4	fails to open; fails to close	mechanical failure; stuck contacts relay failure; control power fails; fire; loss of ventilation	1. Fails to open: back up breaker opens and loss of 1EA2 bus 2. Fails to close: loss of power to 1EB4	1. protective relays 2. Annunciation in Control Room	None: Load supplied by redundant load group provided from bus 1EA1
14A	8-kV cable	connects circuit breaker and transformer T1EB4	short circuit; open circuit	mechanical damage; fire	loss of power to bus 1EB4	1. protective relays 2. Annunciation in Control Room	None: Load supplied by redundant load group provided from bus 1EA1

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 9 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
15	6.9-kV circuit breaker	diesel generator 1EG1 supply breaker	fails to close; fails to open	control failure; mechanical failure; relay failure; stuck contacts; fire; loss of ventilation	1. Fails to close; 1EG1 cannot supply power to bus 1EA1. 2. Fails to open: possible damage to bus 1EA1 and diesel generator 1EG1	1. periodic testing 2. Annunciation in Control Room	None: redundant loads supplied from bus 1EA2 by diesel generator 1EG2
15A	8-kV cable	connects 1EG1 to bus 1EA1 circuit breaker (Item 15)	short circuit; open circuit	mechanical damage; fire	does not transmit power from 1EG1 to bus 1EA1	1. periodic testing 2. Annunciation in Control Room	None: redundant loads supplied from bus 1EA2 by diesel generator 1EG2
15B	Diesel generator 1EG1	provides standby power for Train A loads	delivers no power to bus 1EA1	does not start; component failure; fire; loss of heating or ventilation, or both; spurious relay trip; loss of Control Power	does not transmit power from 1EG1 to bus 1EA1	1. relays and annunciation in control room 2. Periodic testing	None: redundant loads supplied from bus 1EA2 by diesel generator 1EG2
15C	15kV jumper cable	connects 1EG1 to PD bus coupler	short circuit	mechanical damage; fire	does not transmit power from 1EG1 to bus 1EA1	1. periodic testing 2. annunciation in control room	None: redundant loads supplied from bus 1EA2 by diesel generator 1EG2
15D	6.9kV bus coupler	provides isolation between 1EG1 and non-safety PD signal	short circuit	mechanical damage; fire	does not transmit power from 1EG1 to bus 1EA1	1. periodic testing 2. annunciation in control room	Non: redundant loads supplied from bus 1EA2 by diesel generator 1EG2

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 10 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
16	6.9-kV circuit breaker	diesel generator 1EG2 supply breaker	fails to close; fails to open	control failure; mechanical failure; relay failure; stuck contacts; fire; loss of ventilation	1. Fails to close: 1EG2 cannot supply power to bus 1EA2. 2. Fails to open: possible damage to bus 1EA2 and diesel generator 1EG2	1. periodic testing 2. Annunciation in Control Room	None: redundant loads supplied from bus 1EA1 by diesel generator 1EG1
16A	8-kV cable	connects 1EG2 to bus 1EA2 circuit breaker (Item 16)	short circuit; open circuit	mechanical damage; fire	does not transmit power from 1EG2 to bus 1EA2	1. periodic testing 2. Annunciation in Control Room	None: redundant loads supplied from bus 1EA1 by diesel generator 1EG1
16B	Diesel generator 1EG2	provides standby power for Train B loads	delivers no power to bus 1EA2	does not start; component failure; fire; loss of heating or ventilation, or both; spurious relay trip; loss of Control Power	does not transmit power from 1EG2 to bus 1EA2	1. relays and annunciation in control room 2. Periodic Testing	None: redundant loads supplied from bus 1EA1 by diesel generator 1EG1
16C	15kV jumper cable	connects 1EG2 to PD discharge bus coupler	short circuit	mechanical damage; fire	does not transmit power from 1EG2 to bus 1EA2	1. periodic testing 2. annunciation in control room	None: redundant loads supplied from bus 1EA1 by diesel generator 1EG1
16D	6.9 kV bus coupler	provides isolation between 1EG2 and non-safety PD discharge signal	short circuit	mechanical damage; fire	does not transmit power from 1EG2 to bus 1EA2	1. periodic testing 2. annunciation in control room	None: redundant loads supplied from bus 1EA1 by diesel generator 1EG1

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 11 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
17	tap box No. 1	supplies offsite power to 6.9-kV buses 2EA1 and 2EA2	short circuit; open circuit	mechanical damage	loss of alternate source to 2EA1 and 2EA2	protective relays; annunciation in control room	None: bus 2EA1 and 2EA2 can be supplied by offsite power source (Item 1) or by diesel generator 2EG1, 2EG2.
17A	tap box No. 3	supplies offsite power to 6.9-kV buses 2EA1 and 2EA2	short circuit; open circuit	mechanical damage	loss of preferred source to 2EA1 and 2EA2	protective relays; annunciation in control room	None: bus 2EA1 and 2EA2 can be supplied by offsite power source (Item 2) or by diesel generator 2EG1, 2EG2.
17B	tap box No. 6	supplies offsite power to 6.9-KV buses 2EA1 and 2EA2	short circuit; open circuit	mechanical damage	loss of preferred source to 2EA1 and 2EA2	protective relays; annunciation in control room	None: buses 2EA1 and 2EA2 can be supplied by offsite power source (Item 2) or diesel generators 2EG1, 2EG2.
17C	tap box No. 2	supplies offsite power to 6.9-kV buses 1EA1 and 1EA2	short circuit; open circuit	mechanical damage	loss of preferred source to 1EA1 and 1EA2	protective relays; annunciation in control room	None: buses 1EA1 and 1EA2 can be supplied by offsite power source (Item 1) or diesel generators 1EG1, 1EG2
17D	tap box No. 5	supplies offsite power to 6.9-kV buses 1EA1 and 1EA2	short circuit; open circuit	mechanical damage	loss of preferred source to 1EA1 and 1EA2	protective relays; annunciation in control room	None: buses 1EA1 and 1EA2 can be supplied by offsite power source (Item 1) or diesel generators 1EG1, 1EG2

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 12 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
18	6.9-kV circuit breaker BT-1EA1	isolates 6.9-kV bus from 480 V load centers for diesel generator testing, only during plant shutdown	fails to close; fails to open	control failure; mechanical failure; relay failures; stuck contacts; fire; loss of ventilation	1. Fails to close: 1EG1 cannot supply power to bus 1EA1. 2. Fails to open; Diesel generator cannot be sequentially loaded without interrupting power to 480 V loads.	1. protective relays; annunciation in control room 2. Periodic Testing	None: redundant loads supplied from bus 1EA2 by diesel generator 1EG2
19	6.9-kV circuit breaker BT-1EA2	isolates 6.9-kV bus from 480 V load centers for diesel generator testing, only during plant shutdown	fails to close; fails to open	control failure; mechanical failure; relay failure; stuck contacts; fire; loss of ventilation	1. Fails to close: 1EG2 cannot supply power to bus 1EA2. 2. Fails to open: Diesel generator cannot be sequentially loaded without interrupting power to 480 V loads.	1. Protective relays; annunciation in control room 2. Periodic Testing	None: redundant loads supplied from bus 1EA1 by diesel generator 1EG1
20	Unit substation transformer T1EB1	supplies power at 480 V to bus 1EB1	fails to transform power	mechanical damage; short circuit; over-heating; fire; loss of ventilation; loss of Control Power	loss of power on bus 1EB1	1. protective relays 2. Annunciation in Control Room	None: Load supplied by redundant load group provided from bus 1EA2
20A	Transformer T1EB1 throat connection	connects transformer to bus circuit breaker	open circuit; short circuit;	mechanical failure; fire	loss of power on bus 1EB1	1. Protective relays 2. Undervoltage 3. Annunciation in Control Room	None: Load supplied by redundant load group provided from bus 1EA2

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 13 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
21	Unit substation transformer T1EB3	supplies power at 480 V to bus 1EB3	fails to transform power	mechanical damage; short circuit; over-heating; fire; loss of ventilation; loss of Control Power	loss of power on bus 1EB3	1. protective relays 2. Annunciation in Control Room	None: Load supplied by redundant load group provided from bus 1EA2
21A	Transformer T1EB3 throat connection	connects transformer to bus circuit breaker	open circuit; short circuit	mechanical failure; fire	loss of power on bus 1EB3	1. Protective relays 2. Undervoltage 3. Annunciation in Control Room	None: load supplied by redundant load group provided from bus 1EA2
22	Unit substation transformer T1EB2	supplies power to 480-V bus 1EB2	fails to transform power	mechanical damage; short circuit; over heating; fire; loss of ventilation; loss of Control Power	loss of power on bus 1EB2	1. protective relays 2. Annunciation in Control Room	None: load supplied by redundant load group provided from bus 1EA1
22A	Transformer T1EB2 throat connection	connects transformer to bus circuit breaker	open circuits; short circuit	mechanical failure; fire	loss of power on bus 1EB2	1. Protective relays 2. Undervoltage 3. Annunciation in Control Room	None: Load supplied by redundant load group provided from bus 1EA1
23	Unit substation transformer T1EB4	supplies power to 480-V bus 1EB4	fails to transform power	mechanical damage; short circuit; overheating; fire; loss of ventilation; loss of Control Power	loss of power on bus 1EB4	1. protective relays 2. Annunciation in Control Room	None: Load supplied by redundant load group provided from bus 1EA1

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 14 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
23A	Transformer T1EB4 throat connection	Connects transformer to bus circuit breaker	open circuit; short circuit	mechanical failure; fire	loss of power on bus 1EB4	1. Protective relays 2. Undervoltage 3. Annunciation in Control Room	None: Load supplied by redundant load group provided from bus 1EA1
24	480-V circuit breaker 1EB1-1	protects bus 1EB1	fails to open; fails to close	mechanical failure; relay failure; control power fail; stuck contacts; fire; loss of ventilation	1. Failure to open could damage bus. Backup breaker opens and loss of bus 1EB1 2. Failure to close: bus not energized	annunciation; periodic testing	None: Redundant load supplied by Train B
25	480-V circuit breaker 1EB3-1	protects bus 1EB3	fails to open; fails to close	mechanical failure; relay failure; control power fail; stuck contacts; fire; loss of ventilation	1. Failure to open could damage bus. Backup breaker opens and loss of bus 1EB3 2. Failure to close: bus not energized	annunciation; periodic testing	None: Redundant loads supplied by Train B
26	480-V circuit breaker 1EB2-1	protects bus 1EB2	fails to open; fails to close	mechanical failure; relay failure; control power fail; stuck contacts; fire; loss of ventilation	1. Failure to open could damage bus. Backup breaker opens and loss of bus 1EB2 2. Failure to close: bus not energized	annunciation; periodic testing	None: Redundant loads supplied by Train A

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 15 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
27	480-V circuit breaker 1EB4-1	protects bus 1EB4	fails to open; fails to close	mechanical failure; relay failure; control power fail; stuck contacts; fire; loss of ventilation	1. Failure to open could damage bus. Backup breaker opens and loss of bus 1EB4 2. Failure to close: bus not energized	annunciation; periodic Testing	None: Redundant loads supplied by train A
28	480-V Bus 1EB1	distributes 480-V power to Train A loads	fails to deliver power	mechanical failure; short circuit; overload; fire; loss of ventilation	loss of power to 480-V loads	1. protective relay operation 2. Annunciation	None: Redundant loads supplied by Train B
29	480-V Bus 1EB3	distributes 480-V power to Train A loads	fails to deliver power	mechanical failure; short circuit; overload; fire; loss of ventilation	loss of power to 480-V loads	1. protective relays operation 2. Annunciation	None: Redundant loads supplied by Train B
30	480-V Bus 1EB2	distributes 480-V power to Train B loads	fails to deliver power	mechanical failure; short circuit; overload; fire; loss of ventilation	loss of power to 480-V loads	1. protective relay operations 2. Annunciation	None: Redundant loads supplied by Train A
31	480-V Bus 1EB4	distributes 480-V power to Train A loads	fails to deliver power	mechanical failure; short circuit; overload; fire; ventilation	loss of power to 480-V loads	1. protective relay operation 2. Annunciation	None: Redundant loads supplied by Train A

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 16 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
32	480-V tie breaker BT-1EB13	provides transfer to alternate power supply	fails to open; fails to close	mechanical failure; relay failure; control power fail; stuck contacts; fire; loss of ventilation	1. Fails to open: backup breaker opens and lose buses 1EB1 and 1EB3 2. Fails to close: cannot transfer to alternate supply	annunciation; periodic testing	None: Redundant loads supplied by Train B
33	480-V tie breaker BT-1EB24	provides transfer to alternate power supply	fails to open; fails to close	mechanical failure; relay failure; control power fail; stuck contacts; fire; loss of ventilation	1. Fails to open: Backup breaker opens and lose buses EB2 and 1EB4 2. Fails to close: cannot transfer to alternate supply	annunciation; periodic testing	None: Redundant loads supplied by Train A
34	480-V circuit breaker	protects unit 1 MCCS supplied by Train A SWGRS.	fails to open; fails to close	mechanical failure; relay failure; control power fail; stuck contacts; fire; loss of ventilation	1. Failure to open could damage bus. Backup breaker opens. 2. Failure to close: MCC not energized	annunciation; periodic testing	None: Redundant equipment supplied from other MCCs
35	600-V cable	transmits power to MCCs (Item 34)	open circuit; short circuit	mechanical damage; fire	loss of power to MCC	Annunciation	None: redundant equipment supplied from other MCCs
36	480-V circuit breaker	protects common MCCs supplied by Train A SWGRS	fails to open; fails to close	mechanical failure; relay failure; control power fail; stuck contacts; fire; loss of ventilation	1. Failure to open could damage bus. Backup breaker opens. 2. Failure to close: MCC not energized	annunciation; periodic testing	None: Redundant equipment supplied from other MCCs

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 17 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
37	600-V cable	transmits power to MCCs (Item 36)	open circuit; short circuit	mechanical damage; fire	loss of power to MCC	Annunciation	None: Redundant equipment supplied from other MCCs
38	480-V circuit breaker	protects unit 1 MCCs supplied by Train B SWGRS	fails to open; fails to close	mechanical failure; relay failure; control power fail; stuck contacts; fire; loss of ventilation	1. Failure to open could damage bus. Backup breaker opens. 2. Failure to close: MCC not energized	annunciation; periodic testing	None: Redundant equipment supplied from other MCCs
39	600-V cable	transmits power to MCCs (Item 38)	open circuit; short circuit	mechanical damage; fire	loss of power to MCC	Annunciation	None: Redundant equipment supplied from other MCCs
40	480-V circuit breaker	protects common MCCs supplied by Train B switchgears	fails to open; fails to close	mechanical failure; relay failure; control power fail; stuck contacts: fire; loss of ventilation	1. Failure to open could damage bus. Backup breaker opens. 2. Failure to close: MCC not energized	annunciation; periodic testing	None: Redundant equipment supplied from other MCCs
41	600-V cable	transmits power to MCCs (Item 40)	open circuit; short circuit	Mechanical damage; fire	loss of power to MCC	Annunciation in Control Room	None: Redundant equipment supplied from other MCCs
42	480-V automatic transfer SW. for Common MCC's, Train A	automatically transfers power from unit 1 or 2 to common MCCs Train A	no undervoltage transfer	stuck contacts; short circuit.	power not available from one of the units	annunciation; in control room	None: redundant common MCCs supplied from opposite train.
43	480-V automatic transfer SW. for Common MCC's Train B	automatically transfers power from unit 1 or 2 to common MCCs Train B	no undervoltage transfer	stuck contacts; short circuit.	power not available from one of the units	annunciation; in control room	None: redundant common MCCs supplied from opposite train.

TABLE 8.3-3
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY AC POWER SYSTEM

(Sheet 18 of 18)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	Failure Detection	Effects on System
44	Unit 1 Train A MCCs supplied by Train A switchgears	distributes 480-V power	fails to deliver power	mechanical failure; short circuit; over-load; fire; loss of ventilation	loss of MCC	Annunciation in control room	None: Item redundant equipment on unit 1 MCCs supplied by Train B switchgears
45	Common Train A MCCs supplied by Train A unit 1 or 2 switchgears	distributes 480-V power	fails to deliver power	mechanical failure; short circuit; over-load; fire; loss of ventilation	loss of MCC	Annunciation in control room	None: redundant equipment on common MCCs supplied by Train B switchgears
46	Unit 1 Train B MCCs supplied by Train B switchgears	distributes 480-V power	fails to deliver power	mechanical failure; short circuit; over-load; fire; loss of ventilation	loss of MCC	Annunciation in control room	None: redundant equipment on unit 1 MCCs supplied by Train A switchgears.
47	Common Train B MCCs supplied by Train B unit 1 or 2 switchgears	distributes 480-V power	fails to deliver power	mechanical failure; short circuit; over-load; fire; loss of ventilation	loss of MCC	Annunciation in Control Room	None: redundant equipment on common MCCs supplied by Train A switchgears.

Notes:

1. The items listed in this Table are shown on the plant one-line diagram, Figure 8.3-1.
2. The analysis listed is for Unit 1; Unit 2 is similar, except for equipment identification numbers.
3. Analysis of the dc system is given in Table 8.3-7.
4. Flooding considerations for the previously mentioned equipment are discussed in Section 8.3.1.1.14.

Abbreviations: Partial discharge (PD).

TABLE 8.3-4
125-Vdc CLASS 1E BATTERY LOAD REQUIREMENTS

Battery	Amperes Per Time Interval After Loss of AC Power		
	0 to 1 Min.	1 to 239 Min.	239 to 240 Min.
BT1ED1, BT1ED2 (BT2ED1, BT2ED2)	558	252	342
		0 to 240 Minutes	
BT1ED3, BT1ED4 (BT2ED3, BT2ED4)		169	

Notes:

1. Batteries will maintain end of duty cycle voltage of 105V with the listed duty cycle load.

2. The duty cycle load of each battery is enveloped by the duty cycle load listed in this Table.

TABLE 8.3-4A
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TABLE 8.3-4B
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TABLE 8.3-4C
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TABLE 8.3-5
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TABLE 8.3-6
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TABLE 8.3-7
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY DC POWER SYSTEM

(Sheet 1 of 11)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	How Failure Is Detected	Effects on System
1	Batteries BT1ED1 and BT1ED3	supplies Train A dc power	fails to provide power	short circuit; cell or component failure	loss of power supply to Train A buses	annunciation; periodic testing	None: Power supplied by battery chargers.
1A	Batteries BT1ED2 and BT1ED4	supplies Train B dc power	fails to provide power	short circuit; cell or component failure	loss of power supply to Train B buses	annunciation; periodic testing	None: Power supplied by battery chargers
2	Battery chargers Train A	supplies rectified dc power from 480-Vac system Train A	fails to provide power	component failure; short circuit; fire	momentary loss of charging to Train A batteries	annunciation; periodic testing	None: Power supplied by station battery or redundant charger.
2A	Battery chargers Train B	supplies rectified dc power from480-Vac system Train B	fails to provide power	component failure; short circuit; fire	momentary loss of charging to Train B batteries	annunciation; periodic testing	None: Power supplied by station battery or redundant charger.
3	600-V cable	transmits dc power to Train A buses	open circuit; short circuit	mechanical damage; fire	loss of charging to Train A Batteries	annunciation; periodic testing	None: Power supplied by station battery.
3A	600-V cable	transmits dc power to Train B buses	open circuit; short circuit	mechanical damage; fire	loss of charging to Train B Batteries	annunciation; periodic testing	None: Power supplied by station battery.
4	Fusible Switch (Station Battery)	protects Train A buses and batteries	Blows at less than rated current	material defect	battery cannot supply power to bus	annunciation in control room	None: Charger will feed Train A bus.
4A	Fusible Switch (Station Battery)	protects Train B buses and batteries	Blows at less than rated current	material defect	battery cannot supply power to bus	annunciation in control room	None: Charger will feed Train B bus.

TABLE 8.3-7
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY DC POWER SYSTEM

(Sheet 2 of 11)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	How Failure Is Detected	Effects on System
5	Circuit Breaker (Battery Charger)	protects Train A bus and charger	fails to open; fails to close	mechanical failure; stuck contacts; fire	fails to open: backup breaker opens and could damage charger; fails to close: power not available from battery charger	annunciation in control room	None: Redundant charger or station battery will be connected to Train A bus
5A	Circuit Breaker (Battery Charger)	protects Train B bus and charger	fails to open; fails to close	mechanical failure; stuck contacts; fire	fails to open: backup breaker opens and could damage charger; fails to close: power not available from battery charger	annunciation in control room	None: Redundant charger or station battery will be connected to Train B bus
6	Bus 1ED1 and 1ED3	distributes Train A dc power	fails to deliver power	short circuit or overload; fire	loss of Train A load group	annunciation in control room	None: redundant loads are supplied by Train B buses
6A	Bus 1ED2 and 1ED4	distributes Train B dc power	fails to deliver power	short circuit or overload; fire	loss of Train B load group	annunciation in control room	None: redundant loads are supplied by Train A buses
7	Circuit breaker	protects Train A inverter	fails to open; fails to close	mechanical failure; stuck contacts; fire	fails to open; could damage inverter, backup breaker opens and loss of DC Bus 1ED1; fails to close: loss of dc power to inverter	annunciation in control room	None: Redundant loads are supplied by Train B inverter

TABLE 8.3-7
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY DC POWER SYSTEM

(Sheet 3 of 11)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	How Failure Is Detected	Effects on System
7A	Circuit breaker	protects Train B inverter	fails to open; fails to close	mechanical failure; stuck contacts; fire	fails to open; could damage inverter, backup breaker opens and loss of DC Bus 1ED2; fails to close: loss of dc power to inverter	annunciation in control room	None: Redundant loads are supplied by Train A inverter
8	Circuit breaker	protects channel inverter supplied from Train A (IV1PC1 & IV1PC3)	fails to open; fails to close	mechanical failure; stuck contacts; fire	fails to open; could damage inverter, backup breaker opens and loss of DC Bus 1ED1; fails to close: loss of dc power to inverter	annunciation in control room	None: Redundant loads are supplied by inverters powered from Train B (IV1PC2 & IV1PC4)
8A	Circuit breaker	protects channel inverter supplied from Train B (IV1PC2 & IV1PC4)	fails to open; fails to close	mechanical failure; stuck contacts; fire	fails to open; could damage inverter, backup breaker opens and loss of DC Bus 1ED2; fails to close: loss of dc power to inverter	annunciation in control room	None: Redundant loads are supplied by inverters powered from Train A (IV1PC1 & IV1PC3)
9	Fusible switch	protects Train A distribution panel	blows at less than rated current	material defect	loss of power to panel	annunciation in control room	None: redundant safety-related equipment supplied by redundant panel of Train B
9A	Fusible switch	protects Train B distribution panel	blows at less than rated current	material defect	loss of power to panel	annunciation in control room	None: redundant safety-related equipment supplied by redundant panel of Train A

TABLE 8.3-7
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY DC POWER SYSTEM

(Sheet 4 of 11)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	How Failure Is Detected	Effects on System
10	600-V cable	transmits dc power to Train A inverter	open circuit short circuit	mechanical damage; fire	loss of dc power to inverter	annunciation; periodic testing	None: redundant safety-related equipment supplied by redundant panel of Train B
10A	600-V cable	transmits dc power to Train B inverter	open circuit short circuit	mechanical damage; fire	loss of dc power to inverter	annunciation; periodic testing	None: redundant safety-related equipment supplied by redundant panel of Train A
11	600-V cable	transmits dc power to channel inverter from Train A	open circuit short circuit	mechanical damage; fire	loss of dc power to inverter	annunciation; periodic testing	None: redundant safety-related equipment supplied by redundant panel of Train B
11A	600-V cable	transmits dc power to channel inverter from Train B	open circuit short circuit	mechanical damage; fire	loss of dc power to inverter	annunciation; periodic testing	None: redundant safety-related equipment supplied by redundant panel of Train A
12	600-V cable	transmits dc power to Train A distribution panel	open circuit short circuit	mechanical damage; fire	loss of dc power to distribution panel	annunciation; periodic testing	None: redundant safety-related equipment supplied by redundant panel of Train B
12A	600-V cable	transmits dc power to Train B distribution panel	open circuit short circuit	mechanical damage; fire	loss of dc power to distribution panel	annunciation; periodic testing	None: redundant safety-related equipment supplied by redundant panel of Train A
13	Inverter Train A	supplies 118-Vac, single phase power	loss of ac output from inverter	Component failure, fire	loss of power to instrument bus from inverter	annunciation; periodic testing	None: 1. Redundant equipment supplied on Train B instrument bus 2. Alternate 120-V, single-phase supply is available

TABLE 8.3-7
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY DC POWER SYSTEM

(Sheet 5 of 11)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	How Failure Is Detected	Effects on System
13A	Inverter Train B	supplies 118-Vac, single phase power	loss of ac output from inverter	component failure, fire	loss of power to instrument bus from inverter	annunciation; periodic testing	None: 1. Redundant equipment supplied on Train A instrument bus 2. Alternate 120-V, single-phase supply is available
14	Inverter IV1PC1 and IV1PC3	supplies 118-Vac, single phase power	loss of ac output from inverter	component failure, fire	loss of power to instrument bus from inverter	annunciation; periodic testing	None: 1. Redundant equipment supplied on instrument buses 1PC2 and 1PC4 2. Alternate 120-V, single phase supply is available
14A	Inverter IV1PC2 and IV1PC4	supplies 118-Vac, single phase power	loss of ac output from inverter	component failure, fire	loss of power to instrument bus from inverter	annunciation periodic testing;	None: 1. Redundant equipment supplied on instrument buses 1PC1 and 1PC3 2. Alternate 120-V, single phase supply is available
15	DELETED						
15A	DELETED						
16	DELETED						
16A	DELETED						

TABLE 8.3-7
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY DC POWER SYSTEM

(Sheet 6 of 11)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	How Failure Is Detected	Effects on System
17	600-V cable	supplies 120-V, single phase power to Train A bus (alternate supply)	open circuit; short circuit	mechanical damage; fire	alternate supply does not furnish power to bus	annunciation; periodic testing	None: inverter supply is available
17A	600-V cable	supplies 120-V, single phase power to Train B bus (alternate supply)	open circuit; short circuit	mechanical damage; fire	alternate supply does not furnish power to bus	annunciation; periodic testing	None: inverter supply is available
18	600-V cable	transmits inverter power to Train A instrument bus	open circuit; short circuit	mechanical damage; fire	momentary loss of power to bus; manual transfer to alternate supply	annunciation; periodic testing	None: 1. Redundant equipment supplied on Train B instrument buses 2. Alternate 120-V, single phase supply is available
18A	600-V cable	transmits inverter power to Train B instrument bus	open circuit; short circuit	mechanical damage; fire	momentary loss of power to bus; manual transfer to alternate supply	annunciation; periodic testing	None: 1. Redundant equipment supplied on Train A instrument buses 2. Alternate 120-V, single phase supply is available
19	600-V cable	transmits inverter power to buses 1PC1 and 1PC3	open circuit; short circuit	mechanical damage; fire	momentary loss of power to bus; manual transfer to alternate supply	annunciation; periodic testing	None: 1. Redundant equipment supplied on instrument buses 1PC2 and 1PC4 2. Alternate 120-V, single phase supply is available

TABLE 8.3-7
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY DC POWER SYSTEM

(Sheet 7 of 11)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	How Failure Is Detected	Effects on System
19A	600-V cable	transmits inverter power to buses 1PC2 and 1PC4	open circuit; short circuit	mechanical damage; fire	momentary loss of power to bus; manual transfer to alternate supply	annunciation; periodic testing	None: 1. Redundant equipment supplied on instrument buses 1PC1 and 1PC3 2. Alternate 120-V, single phase supply is available
20	Circuit breaker	supplies power from inverter to Train A BOP instrument bus	fails to open; fails to close	mechanical failure; stuck contacts, fire	fails to open: could damage bus; fails to close: power cannot be supplied by 120-V alternate source	annunciation; periodic testing	None: redundant equipment to Train B buses; inverter supply available
20A	Circuit breaker	supplies power from inverter to Train B BOP instrument bus	fails to open; fails to close	mechanical failure; stuck contacts, fire	fails to open: could damage bus; fails to close: power cannot be supplied by 120-V alternate source	annunciation; periodic testing	None: redundant equipment to Train A buses; inverter supply available
21	Circuit breaker	supplies power from inverter to Train A BOP instrument bus	fails to open; fails to close	mechanical failure; stuck contacts, fire	fails to open: could damage bus; fails to close: power cannot be supplied by Train A inverter	annunciation; periodic testing	None: 1. Redundant equipment supplied on Train B instrument buses 2. Alternate 120-V, single phase supply is available

TABLE 8.3-7
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY DC POWER SYSTEM

(Sheet 8 of 11)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	How Failure Is Detected	Effects on System
21A	Circuit breaker	supplies power from inverter to Train B BOP instrument bus	fails to open; fails to close	mechanical failure; stuck contacts, fire	fails to open: could damage bus; fails to close: power cannot be supplied by Train B inverter	annunciation; periodic testing	None: 1. Redundant equipment supplied on Train A instrument buses 2. Alternate 120-V, single phase supply is available
22	Circuit breaker	protects instrument buses 1PC1 and 1PC3	fails to open; fails to close	mechanical failure; stuck contacts, fire	fails to open: could damage bus; fails to close: power cannot be supplied by 120-V alternate source	annunciation; periodic testing	None: redundant equipment on buses 1PC2 and 1PC4; inverter supply available
22A	Circuit breaker	protects instrument buses 1PC2 and 1PC4	fails to open fails to close	mechanical failure; stuck contacts, fire	fails to open: could damage bus; fails to close: power cannot be supplied by 120-V alternate source	annunciation; periodic testing	None: redundant equipment on buses 1PC1 and 1PC3; inverter supply available
23	Circuit breaker	protects instrument buses 1PC1 and 1PC3	fails to open; fails to close	mechanical failure; stuck contacts, fire	fails to open: could damage bus; fails to close: power cannot be supplied by IV1PC1 and IV1PC3	annunciation; periodic testing	None: 1. Redundant equipment supplied on instrument buses inverters 1PC2 and 1PC4 2. Alternate 120-V, single phase supply

TABLE 8.3-7
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY DC POWER SYSTEM

(Sheet 9 of 11)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	How Failure Is Detected	Effects on System
23A	Circuit breaker	protects instrument buses 1PC2 and 1PC4	fails to open; fails to close	mechanical failure; stuck contacts, fire	fails to open: could damage bus; fails to close: power cannot be supplied by inverters IV1PC2 and IV1PC4	annunciation; periodic testing	None: 1. Redundant equipment supplied on instrument bus 1PC1 and 1PC3 2. Alternate 120-V, single phase supply is available
24	BOP instrument bus Train A	supplies ac power to BOP instrumentation	fails to deliver power	short circuit or overload; fire	loss of power to instrument loads	annunciation; periodic testing	None: redundant BOP loads provided on Train B buses
24A	BOP instrument bus Train B	supplies ac power to BOP instrumentation	fails to deliver power	short circuit or overload; fire	loss of power to instrument loads	annunciation; periodic testing	None: redundant BOP loads provided on Train A buses
25	Instrumentation buses 1PC1 and 1PC3	distributes instrumentation power to systems	fails to deliver power	short circuit or overload; fire	loss of one load group of instrumentation	annunciation; periodic testing	None: redundant loads provided by buses 1PC2 and 1PC4
25A	Instrumentation buses 1PC2 and 1PC4	distributes instrumentation power to systems	fails to deliver power	short circuit or overload; fire	loss of one load group of instrumentation	annunciation; periodic testing	None: redundant loads provided by buses 1PC1 and 1PC3
26	Train A distribution panel	distributes power to auxiliaries	fails to deliver power	short circuit or overload; fire	loss of panel	annunciation; periodic testing	None: redundant loads provided by Train B buses
26A	Train B distribution panel	distributes power to auxiliaries	fails to deliver power	short circuit or overload; fire	loss of panel	annunciation; periodic testing;	None: redundant loads provided by Train A buses

TABLE 8.3-7
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY DC POWER SYSTEM

(Sheet 10 of 11)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	How Failure Is Detected	Effects on System
27	120-V bypass transformer Train A	supplies 120-V, single phase power to instrument buses (alternate supply) and BOP inverter's static switch	open circuit; short circuit	mechanical damage; short circuit; fire	alternate supply does not furnish power to bus	annunciation; periodic testing	None: inverter supplies are available
27A	120-V, bypass transformer Train B	supplies 120-V, single phase power to instrument buses (alternate supply) and BOP inverter's static switch	open circuit; short circuit	mechanical damage; short circuit; fire	alternate supply does not furnish power to bus	annunciation; periodic testing	None: inverter supplies are available
28	600-V cable	supplies Unit 1 dc power to Train A common distribution panel	open circuit; short circuit	mechanical damage; fire	loss of Unit 1 power to panel	annunciation; periodic testing	None: 1. Unit 2 power is available 2. Redundant loads are supplied by Train B common panel
28A	600-V cable	supplies Unit 1 dc power to Train B common distribution panel	open circuit; short circuit	mechanical damage; fire	loss of Unit 1 power to panel	annunciation; periodic testing	None: 1. Unit 2 power is available 2. Redundant loads are supplied by Train A common panel

TABLE 8.3-7
FAILURE MODE AND EFFECT ANALYSIS FOR AUXILIARY DC POWER SYSTEM

(Sheet 11 of 11)

Item	Description	Function	Failure Mode	Causes of Failure	Effects of Failure	How Failure Is Detected	Effects on System
29	600-V cable	supplies Unit 2 dc power to Train A common distribution panel	open circuit; short circuit	mechanical damage; fire	loss of Unit 2 power to panel	annunciation; periodic testing	None: 1. Unit 1 power is available 2. Redundant loads are supplied by Train B common panel
29A	600-V cable	supplies Unit 2 dc power to Train B common distribution panel	open circuit; short circuit	mechanical damage; fire	loss of Unit 2 power to panel	annunciation; periodic testing	None: 1. Unit 1 power is available 2. Redundant loads are supplied by Train A common panel
30	Automatic transfer switch	automatically transfers power from Unit 1 or 2 to common Train A panel	no undervoltage transfer	stuck contacts; short circuit, fire	power not available from one of the units	annunciation; periodic testing	None: redundant loads supplied by Train B common panel
30A	Automatic transfer switch	automatically transfer power from Unit 1 or 2 to common Train B panel	no undervoltage transfer	stuck contacts; short circuit, fire	power not available from one of the units	annunciation; periodic testing	None: redundant loads supplied by Train A common panel

Notes:

1. The items listed in this table are shown on the one-line diagram Figure 8.3-13.

2. Analysis listed is for Unit 1: Unit 2 similar except for equipment identification numbers

TABLE 8.3-8
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TABLE 8.3-9
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TABLE 8.3-10
ELECTRICAL EQUIPMENT NOT REQUIRING INTERNAL CABLE SEPARATION

(Sheet 1 of 11)

EQUIPMENT TAG NO.	DESCRIPTION	DIFFERENT COLOR-CODED CABLE WITHIN	NOTES
1-NY-0050A-1	NIS NEUTRON FLUX PREAMPLIFIER ASSEMBLY (1E)	ORANGE, BLUE	1
1-NY-0050A-2	NIS NEUTRON FLUX SIGNAL PROCESSOR (1E)	ORANGE, BLUE, BLACK	1
1-NY-0050A-3	NIS NEUTRON FLUX ISOLATOR EXPANSION ASSEMBLY (1E)	ORANGE, BLUE, BLACK	1
1-NY-0050B-1	NIS NEUTRON FLUX PREAMPLIFIER ASSEMBLY (1E)	GREEN, YELLOW	1
1-NY-0050B-2	NIS NEUTRON FLUX SIGNAL PROCESSOR (1E)	GREEN, YELLOW, BLACK	1
1-NY-0050B-3	NIS NEUTRON FLUX ISOLATOR EXPANSION ASSEMBLY (1E)	GREEN, YELLOW, BLACK	1
1-SSII-1	SAFETY SYSTEM INOPERABLE INDICATION PANEL 1	ASSOCIATED ORANGE TO BLACK	5
1-SSII-2	SAFETY SYSTEM INOPERABLE INDICATION PANEL 2	ASSOCIATED GREEN TO BLACK	5
2-NY-0050A-1	NIS NEUTRON FLUX PREAMPLIFIER ASSEMBLY (1E)	ORANGE, BLUE	1
2-NY-0050A-2	NIS NEUTRON FLUX SIGNAL PROCESSOR (1E)	ORANGE, BLUE, BLACK	1
2-NY-0050A-3	NIS NEUTRON FLUX ISOLATOR EXPANSION ASSEMBLY (1E)	ORANGE, BLUE, BLACK	1
2-NY-0050B-1	NIS NEUTRON FLUX PREAMPLIFIER ASSEMBLY (1E)	GREEN, YELLOW	1
2-NY-0050B-2	NIS NEUTRON FLUX SIGNAL PROCESSOR (1E)	GREEN, YELLOW, BLACK	1
2-NY-0050B-3	NIS NEUTRON FLUX ISOLATOR EXPANSION ASSEMBLY (1E)	GREEN, YELLOW, BLACK	1
2-SSII-1	SAFETY SYSTEM INOPERABLE INDICATION PANEL 1	ASSOCIATED ORANGE TO BLACK	5
2-SSII-2	SAFETY SYSTEM INOPERABLE INDICATION PANEL 2	ASSOCIATED GREEN TO BLACK	5
CP1-ECDPPC-01 (1PC1)	INSTRUMENT POWER PANEL	ORANGE, RED, BLACK	8
CP1-ECDPPC-02 (1PC2)	INSTRUMENT POWER PANEL	GREEN, WHITE, BLACK	8
CP1-ECDPPC-03 (1PC3)	INSTRUMENT POWER PANEL	ORANGE, BLUE, BLACK	8
CP1-ECDPPC-04 (1PC4)	INSTRUMENT POWER PANEL	GREEN, YELLOW, BLACK	8
CP1-EIPRC1-01 (1-CI-01)	BOP ANALOG PROCESS INSTRUMENTATION RACKS	ORANGE, BLUE	6
CP1-IEPRCI-02 (1-CI-02)	BOP ANALOG PROCESS INSTRUMENTATION RACKS	GREEN, BLACK	6
CP1-ELDPEC-01(ESB1)	LTG DISTR PNLBD (1E)	ORANGE AND ASSOCIATED ORANGE TO BLACK	3

TABLE 8.3-10
ELECTRICAL EQUIPMENT NOT REQUIRING INTERNAL CABLE SEPARATION

(Sheet 2 of 11)

EQUIPMENT TAG NO.	DESCRIPTION	DIFFERENT COLOR-CODED CABLE WITHIN	NOTES
CP1-ELDPEC-02(ESB2)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CP1-EPDSNA-01	ALTERNATE POWER TRANSFER SWITCH	ASSOCIATED ORANGE TO ASSOCIATED GREEN ASSOCIATED ORANGE OR GREEN TO BLACK	13
CP1-EPTRNT-12 (T1C3)	BYPASS TRANSFORMER (NON 1E)	ASSOCIATED ORANGE TO BLACK	2
CP1-EC1VEC-05	SPARE INVERTER (1E)	ORANGE AND RED OR ORANGE AND BLUE	16
CP1-EC1VEC-06	SPARE INVERTER (1E)	GREEN AND WHITE OR GREEN AND YELLOW	16
CP1-CICACO-01A	INSTRUMENT AIR COMPRESSOR TERMINATION CABINET	ASSOCIATED ORANGE TO BLACK	2
CP1-ELDPEC-03(ESB3)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CP1-ELDPEC-04(ESB4)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CP1-ELDPEC-05(ESB5)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CP1-ELDPEC-06(ESB6)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CP1-ELDPEC-07(ESB7)	LTG DISTR PNLBD (1E)	ORANGE AND ASSOCIATED ORANGE TO BLACK	3
CP1-ELDPEC-08(ESB8)	LTG DISTR PNLBD (1E)	GREEN AND ASSOCIATED GREEN TO BLACK	3
CP1-ELDPEC-09(ESB9)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CP1-ELDPEC-10(ESB10)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CP1-ELDPEC-11(ESB11)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CP1-ELDPEC-12(ESB12)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CP1-ELDPEC-13(ESB13)	LTG DISTR PNLBD (1E)	ORANGE AND ASSOCIATED ORANGE TO BLACK	3
CP1-ELDPEC-14(ESB14)	LTG DISTR PNLBD (1E)	GREEN AND ASSOCIATED GREEN TO BLACK	3
CP1-ELTRNT-18(XF-SC1-3)	LIGHTING TRANSFORMER (NON 1E)	ASSOCIATED ORANGE TO BLACK	3
CP1-ELTRNT-19(XF-SC2-4)	LIGHTING TRANSFORMER (NON 1E)	ASSOCIATED GREEN TO BLACK	3
CP1-EPBCND-02 (BC1D2)	BATTERY CHARGER (NON 1E)	ASSOCIATED GREEN TO BLACK	2
CP1-EPBCND-04 (BC1D4)	BATTERY CHARGER (NON 1E)	ASSOCIATED GREEN TO BLACK	2

TABLE 8.3-10
ELECTRICAL EQUIPMENT NOT REQUIRING INTERNAL CABLE SEPARATION

(Sheet 3 of 11)

EQUIPMENT TAG NO.	DESCRIPTION	DIFFERENT COLOR-CODED CABLE WITHIN	NOTES
CP1-EPTRNT-28 (T1EC3-3)	ISOLATION TRANSFORMER (NON 1E) ASSOCIATED	ASSOCIATED ORANGE TO BLACK	3
CP1-ECTRET-03,04,05 & 06	PT CABINET (1E)	--	12
CP2-ECTRET-03,04,05 & 06	PT CABINET (1E)	--	12
CP2-ECDPPC-01(2PC1)	INSTRUMENT POWER PANEL	ORANGE, RED, BLACK	8
CP2-CICACO-01B	INSTRUMENT AIR COMPRESSOR CONTROL PANEL	ASSOCIATED ORANGE TO BLACK	2
CP2-ECDPPC-02(2PC2)	INSTRUMENT POWER PANEL	GREEN, WHITE, BLACK	8
CP2-ECDPPC-03(2PC3)	INSTRUMENT POWER PANEL	ORANGE, BLUE, BLACK	8
CP2-ECDPPC-04(2PC4)	INSTRUMENT POWER PANEL	GREEN, YELLOW, BLACK	8
CP2-EIPRCI-01 (2-CI-01)	BOP ANALOG PROCESS INSTRUMENTATION RACKS	ORANGE, BLACK	6
CP2-EIPRCI-02 (2-CI-02)	BOP ANALOG PROCESS INSTRUMENTATION RACKS	GREEN, BLACK	6
CP2-ELDPEC-01(2ESB1)	LTG DISTR PNLBD (1E)	ORANGE AND ASSOCIATED ORANGE TO BLACK	3
CP2-ELDPEC-02(2ESB2)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CP2-ELDPEC-03(2ESB3)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CP2-EPDSNA-01	ALTERNATE POWER TRANSFER SWITCH	ASSOCIATED ORANGE TO ASSOCIATED GREEN ASSOCIATED ORANGE OR GREEN TO BLACK	13
CP2-EIPRLV-48	TURBINE DRIVEN AFW PUMP INSTRUMENT RACK	ASSOCIATED ORANGE TO BLACK	5
CP2-ELDPEC-04(2ESB4)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CP2-ELDPEC-05(2ESB5)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CP2-ELDPEC-06(2ESB6)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CP2-ELDPEC-07(2ESB7)	LTG DISTR PNLBD (1E)	ORANGE AND ASSOCIATED ORANGE TO BLACK	3
CP2-ELDPEC-08(2ESB8)	LTG DISTR PNLBD (1E)	GREEN AND ASSOCIATED GREEN TO BLACK	3
CP2-ELDPEC-09(2ESB9)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CP2-ELDPEC-10(2ESB10)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3

TABLE 8.3-10
ELECTRICAL EQUIPMENT NOT REQUIRING INTERNAL CABLE SEPARATION

(Sheet 4 of 11)

EQUIPMENT TAG NO.	DESCRIPTION	DIFFERENT COLOR-CODED CABLE WITHIN	NOTES
CP2-ELDPEC-11(2ESBD1)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CP2-ELDPEC-12(2ESBD2)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CP2-ELDPEC-13(2ECB3)	LTG DISTR PNLBD (1E)	ORANGE AND ASSOCIATED ORANGE TO BLACK	3
CP2-ELDPEC-14(2ECB4)	LTG DISTR PNLBD (1E)	GREEN AND ASSOCIATED GREEN TO BLACK	3
CP2-ELTRNT-18 (XF-2SC1-3)	LIGHTING TRANSFORMER (NON 1E)	ASSOCIATED ORANGE TO BLACK	3
CP2-ELTRNT-19 (XF-2SC2-4)	LIGHTING TRANSFORMER (NON 1E)	ASSOCIATED GREEN TO BLACK	3
CP2-EPBCND-02 (BC2D2)	BATTERY CHARGER (NON 1E)	ASSOCIATED GREEN TO BLACK	2
CP2-EPBCND-04 (BC2D4)	BATTERY CHARGER (NON 1E)	ASSOCIATED GREEN TO BLACK	2
CP2-EPTRNT-28 (T2EC3-3)	ISOLATION TRANSFORMER (NON 1E)	ASSOCIATED ORANGE TO BLACK	3
CPX-EIPRCI-06 (X-CI-06)	BOP ANALOG PROCESS INSTRUMENTATION RACKS	ORANGE, ASSOCIATED ORANGE, BLACK	6
CPX-EIPRCI-07 (X-CI-07)	BOP ANALOG PROCESS INSTRUMENTATION RACKS	GREEN, ASSOCIATED GREEN, BLACK	6
CPX-EIPRLV-29 (X-LV-29)	LOCAL FIRE DET. PANEL (NON 1E)	ASSOCIATED GREEN TO BLACK	4
CPX-EIPRLV-29A (X-LV-29A)	LOCAL FIRE DET. PANEL (NON 1E)	ASSOCIATED ORANGE TO BLACK	4
CPX-EIPRLV-30 (X-LV-30)	LOCAL FIRE DET. PANEL (NON 1E)	ASSOCIATED ORANGE & ASSOCIATED GREEN TO BLACK	4
CPX-ELDPEC-03 (ECB1)	LTG DISTR PNLBD (1E)	ORANGE AND ASSOCIATED ORANGE TO BLACK	3
CPX-ELDPEC-04 (ECB2)	LTG DISTR PNLBD (1E)	GREEN AND ASSOCIATED GREEN TO BLACK	3
CPX-ELDPEC-05 (ECB5)	LTG DISTR PNLBD (1E)	ORANGE AND ASSOCIATED ORANGE TO BLACK	3
CPX-ELDPEC-06 (ECB6)	LTG DISTR PNLBD (1E)	GREEN AND ASSOCIATED GREEN TO BLACK	3
CPX-ELDPEC-07 (EAB1)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CPX-ELDPEC-08 (EAB2)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CPX-ELDPEC-09 (EAB3)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CPX-ELDPEC-10 (EAB4)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3

TABLE 8.3-10
ELECTRICAL EQUIPMENT NOT REQUIRING INTERNAL CABLE SEPARATION

(Sheet 5 of 11)

EQUIPMENT TAG NO.	DESCRIPTION	DIFFERENT COLOR-CODED CABLE WITHIN	NOTES
CPX-ELDPEC-11 (EAB5)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CPX-ELDPEC-12 (EAB6)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CPX-ELDPEC-13 (EAB7)	LTG DISTR PNLBD (1E)	ORANGE AND ASSOCIATED ORANGE TO BLACK	3
CPX-ELDPEC-14 (EAB8)	LTG DISTR PNLBD (1E)	GREEN AND ASSOCIATED GREEN TO BLACK	3
CPX-ELDPEC-15 (EAB9)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CPX-ELDPEC-16 (EAB10)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CPX-ELDPEC-17 (EAB11)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CPX-ELDPEC-18 (EAB12)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CPX-ELDPEC-21 (EABD1)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CPX-ELDPEC-22 (EABD2)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CPX-ELDPEC-23 (ECBD3)	LTG DISTR PNLBD (1E)	ORANGE TO BLACK	3
CPX-ELDPEC-24 (ECBD4)	LTG DISTR PNLBD (1E)	GREEN TO BLACK	3
CPX-EPMCEB-05 (XEB3-3)	MOTOR CONTROL CENTER (NON 1E)	ASSOCIATED ORANGE TO BLACK	2
CPX-EPMCEB-06 (XEB4-3)	MOTOR CONTROL CENTER (NON 1E)	ASSOCIATED GREEN TO BLACK	2
CPX-EPTRNT-42 (TXEC1)	REGULATING TRANSFORMER (NON 1E)	ASSOCIATED ORANGE TO BLACK	3
CPX-EPTRNT-43 (TXEC2)	REGULATING TRANSFORMER (NON 1E)	ASSOCIATED GREEN TO BLACK	3
CPX-EPTRNT-44 (TXEC3)	REGULATING TRANSFORMER (NON 1E)	ASSOCIATED ORANGE TO BLACK	3
CPX-EPTRNT-45 (TXEC4)	REGULATING TRANSFORMER (NON 1E)	ASSOCIATED GREEN TO BLACK	3
TBX-ASELIV-01 (IV1C1)	INVERTER (NON 1E)	ASSOCIATED ORANGE TO BLACK	2
TBX-ESELAR-01 (1-AR-01)	NSSS AUXILIARY RELAY CABINETS	ORANGE, GREEN, ASSOC. ORANGE, ASSOC. GREEN, BLACK	9
TBX-ESELIV-01 (IV1PC1)	INVERTER (1E)	ORANGE TO RED	1
TBX-ESELIV-02 (IV1PC2)	INVERTER (1E)	GREEN TO WHITE	1

TABLE 8.3-10
ELECTRICAL EQUIPMENT NOT REQUIRING INTERNAL CABLE SEPARATION

(Sheet 6 of 11)

EQUIPMENT TAG NO.	DESCRIPTION	DIFFERENT COLOR-CODED CABLE WITHIN	NOTES
TBX-ESELIV-03 (IV1PC3)	INVERTER (1E)	ORANGE TO BLUE	1
TBX-ESELIV-04 (IV1PC4)	INVERTER (1E)	GREEN TO YELLOW	1
TBX-ESELSP-01 (1-SP-01)	REACTOR SOLID STATE PROTECTION PANEL	ORANGE, GREEN, ASSOCIATED ORANGE, ASSOCIATED GREEN, RED, WHITE, BLUE, YELLOW, BLACK	6, 7
TBX-ESELTC-01 (1-ETC-01)	REACTOR SAFEGUARDS TEST CABINET	ORANGE, GREEN, ASSOCIATED ORANGE, ASSOCIATED GREEN	6
TBX-ESPDTS-01 (1-TS-01)	REACTOR TRIP SWITCHGEAR CABINETS	ORANGE, GREEN, BLACK	6
TBX-NIELCA-01 (1-LCA-01)	NUCLEAR INSTRUMENTATION RACKS	RED, WHITE, BLUE, YELLOW, BLACK	6
TBX-XIELRK-01 (1-RK-01)	NSSS ANALOG PROCESS INSTRUMENTATION RACKS	ORANGE, RED, BLACK	6
TBX-XIELRK-02 (1-RK-02)	NSSS ANALOG PROCESS INSTRUMENTATION RACKS	GREEN, WHITE, BLACK	6
TBX-XIELRK-03 (1-RK-03)	NSSS ANALOG PROCESS INSTRUMENTATION RACKS	ORANGE, BLUE, BLACK	6
TBX-XIELRK-04 (1-RK-04)	NSSS ANALOG PROCESS INSTRUMENTATION RACKS	GREEN, YELLOW, BLACK	6
TBX-XIELSS-50IX (1-SS-50IX)	UPGRADE SURVEILLANCE AND PROTECTION PANEL	ORANGE, RED, BLUE, BLACK	6
TBX-XIELSS-50X (1-SS-50X)	UPGRADE SURVEILLANCE AND PROTECTION PANEL	GREEN, WHITE, YELLOW, BLACK	6
TCX-ESELAR-01 (2-AR-01)	NSSS AUXILIARY RELAY CABINETS	ORANGE, GREEN, ASSOC. ORANGE, ASSOC. GREEN, BLACK	9
TCX-ESELIV-01 (IV2PC1)	INVERTER (1E)	ORANGE TO RED	1
TCX-ESELIV-02 (IV2PC2)	INVERTER (1E)	GREEN TO WHITE	1
TCX-ESELIV-03 (IV2PC3)	INVERTER (1E)	ORANGE TO BLUE	1
TCX-ESELIV-04 (IV2PC4)	INVERTER (1E)	GREEN TO YELLOW	1
TCX-ESELSP-01 (2-SP-01)	REACTOR SOLID STATE PROTECTION PANEL	ORANGE, GREEN, ASSOCIATED ORANGE, ASSOCIATED GREEN, RED, WHITE, BLUE, YELLOW, BLACK	6, 7
TCX-ESELTC-01 (2-ETC-01)	REACTOR SAFEGUARDS TEST CABINET	ORANGE, GREEN, ASSOCIATED ORANGE, ASSOCIATED GREEN	6
TCX-ESPDTS-01 (2-TS-01)	REACTOR TRIP SWITCHGEAR CABINETS	ORANGE, GREEN, BLACK	6

TABLE 8.3-10
ELECTRICAL EQUIPMENT NOT REQUIRING INTERNAL CABLE SEPARATION

(Sheet 7 of 11)

EQUIPMENT TAG NO.	DESCRIPTION	DIFFERENT COLOR-CODED CABLE WITHIN	NOTES
TCX-NIELCA-01 (2-LCA-01)	NUCLEAR INSTRUMENTATION RACKS	RED, WHITE, BLUE, YELLOW, BLACK	6
TCX-XIELRK-01 (2-RK-01)	NSSS ANALOG PROCESS INSTRUMENTATION RACKS	ORANGE, RED, BLACK	6
TCX-XIELRK-02 (2-RK-02)	NSSS ANALOG PROCESS INSTRUMENTATION RACKS	GREEN, WHITE, BLACK	6
TCX-XIELRK-03 (2-RK-03)	NSSS ANALOG PROCESS INSTRUMENTATION RACKS	ORANGE, BLUE, BLACK	6
TCX-XIELRK-04 (2-RK-04)	NSSS ANALOG PROCESS INSTRUMENTATION RACKS	GREEN, YELLOW, BLACK	6
TCX-XIELSS-50IX (2-SS-50IX)	UPGRADE SURVEILLANCE AND PROTECTION PANEL	ORANGE, RED, BLUE, BLACK	6
TCX-XIELSS-50X (2-SS-50X)	UPGRADE SURVEILLANCE AND PROTECTION PANEL	GREEN, WHITE, YELLOW, BLACK	6
CPX-EPTSEB-01	MANUAL TRANSFER SWITCH	GREEN TO BLACK	14
CPX-EPTSEB-02	MANUAL TRANSFER SWITCH	ASSOCIATED GREEN TO BLACK	11
CPX-EPTSEB-03	MANUAL TRANSFER SWITCH	ASSOCIATED ORANGE TO BLACK	11
CPX-EPTSEB-04	MANUAL TRANSFER SWTICH	ORANGE TO BLACK	11
CP1-EPTSEB-01	MANUAL TRANSFER SWITCH	ORANGE TO BLACK	11
CP1-EPTSEB-03	MANUAL TRANSFER SWITCH	ORANGE TO BLACK	11
CP1-EPTSEB-06	MANUAL TRANSFER SWITCH	GREEN TO BLACK	11
CP1-EPTSEB-07	MANUAL TRANSFER SWITCH	ASSOCIATED GREEN TO BLACK	11
CP1-EPTSEB-08	MANUAL TRANSFER SWITCH	GREEN TO BLACK	11
CP1-EPTSEB-09	MANUAL TRANSFER SWITCH	GREEN TO BLACK	11
CP1-EPTSEB-11	MANUAL TRANSFER SWITCH	ASSOCIATED GREEN TO BLACK	11
CP1-EPTSEB-12	MANUAL TRANSFER SWITCH	GREEN TO BLACK	11
CP1-EPTSEB-14	MANUAL TRANSFER SWITCH	GREEN TO BLACK	11
CP1-EPTSEB-16	MANUAL TRANSFER SWITCH	ORANGE TO BLACK	11
CP1-EPTSEB-17	MANUAL TRANSFER SWITCH	ORANGE TO BLACK	11
CP1-EPTSEB-18	MANUAL TRANSFER SWITCH	ORANGE TO BLACK	11

TABLE 8.3-10
ELECTRICAL EQUIPMENT NOT REQUIRING INTERNAL CABLE SEPARATION

(Sheet 8 of 11)

EQUIPMENT TAG NO.	DESCRIPTION	DIFFERENT COLOR-CODED CABLE WITHIN	NOTES
CP2-EPTSEB-01	MANUAL TRANSFER SWITCH	GREEN TO BLACK	11
CP2-EPTSEB-02	MANUAL TRANSFER SWITCH	GREEN TO BLACK	11
CP2-EPTSEB-03	MANUAL TRANSFER SWITCH	ASSOCIATED GREEN TO BLACK	11
CP2-EPTSEB-04	MANUAL TRANSFER SWITCH	GREEN TO BLACK	11
CP2-EPTSEB-06	MANUAL TRANSFER SWTICH	ORANGE TO BLACK	11
CP2-EPTSEB-07	MANUAL TRANSFER SWITCH	ORANGE TO BLACK	11
CP2-EPTSEB-08	MANUAL TRANSFER SWITCH	ORANGE TO BLACK	11
CP2-EPTSEB-09	MANUAL TRANSFER SWITCH	ORANGE TO BLACK	11
CP2-EPTSEB-10	MANUAL TRANSFER SWITCH	ORANGE TO BLACK	11
CP2-EPTSEB-11	MANUAL TRANSFER SWITCH	ASSOCIATED ORANGE TO BLACK	11
CP2-EPTSEB-12	MANUAL TRANSFER SWITCH	GREEN TO BLACK	11
CP2-EPTSEB-13	MANUAL TRANSFER SWITCH	GREEN TO BLACK	11
CP1-EPSWEA-01	6.9kV SAFEGUARD BUS 1EA1	ORANGE, BLACK	10
CP1-EPSWEA-02	6.9kV SAFEGUARD BUS 1EA2	GREEN, BLACK	10
CP2-EPSWEA-01	6.9kV SAFEGUARD BUS 2EA1	ORANGE, BLACK	10
CP2-EPSWEA-02	6.9kV SAFEGUARD BUS 2EA2	GREEN, BLACK	10
X-LY-4849A-1	ELECTRONICS BOX FOR LEVEL SWITCH X-LS-4849A-1	ORANGE, BLACK	14
X-LY-4849A-2	ELECTRONICS BOX FOR LEVEL SWITCH X-LS-4849A-2	ORANGE, BLACK	14
X-LY-4849B-1	ELECTRONICS BOX FOR LEVEL SWITCH X-LS-4849B-1	GREEN, BLACK	14
X-LY-4849B-2	ELECTRONICS BOX FOR LEVEL SWITCH X-LS-4849B-2	GREEN, BLACK	14
1-TE-3419-2A	1EG1 GEN. STATOR RTD	-	15
1-TE-3419-2B	1EG1 GEN. STATOR RTD	-	15
1-TE-3419-2C	1EG1 GEN. STATOR RTD	-	15

TABLE 8.3-10
ELECTRICAL EQUIPMENT NOT REQUIRING INTERNAL CABLE SEPARATION

(Sheet 9 of 11)

EQUIPMENT TAG NO.	DESCRIPTION	DIFFERENT COLOR-CODED CABLE WITHIN	NOTES
1-TE-3419-2D	1EG1 GEN. STATOR RTD	-	15
1-TE-3419-2E	1EG1 GEN. STATOR RTD	-	15
1-TE-3419-2F	1EG1 GEN. STATOR RTD	-	15
1-TE-3420-2A	1EG2 GEN. STATOR RTD	-	15
1-TE-3420-2B	1EG2 GEN. STATOR RTD	-	15
1-TE-3420-2C	1EG2 GEN. STATOR RTD	-	15
1-TE-3420-2D	1EG2 GEN. STATOR RTD	-	15
1-TE-3420-2E	1EG2 GEN. STATOR RTD	-	15
1-TE-3420-2F	1EG2 GEN. STATOR RTD	-	15
CP1-BSCPEB-01	PERSONNEL AIRLOCK HVD FDR CONT. PNL	GREEN, BLACK	17
CP2-BSCPEB-01	PERSONNEL AIRLOCK HVD FDR CONT. PNL	GREEN, BLACK	17
2-TE-3419-2A	2EG1 GEN. STATOR RTD	GREEN, BLACK	15
2-TE-3419-2B	2EG1 GEN. STATOR RTD	GREEN, BLACK	15
2-TE-3419-2C	2EG1 GEN. STATOR RTD	GREEN, BLACK	15
2-TE-3419-2D	2EG1 GEN. STATOR RTD	GREEN, BLACK	15
2-TE-3419-2E	2EG1 GEN. STATOR RTD	GREEN, BLACK	15
2-TE-3419-2F	2EG1 GEN. STATOR RTD	GREEN, BLACK	15
2-TE-3420-2A	2EG2 GEN. STATOR RTD	GREEN, BLACK	15
2-TE-3420-2B	2EG2 GEN. STATOR RTD	GREEN, BLACK	15
2-TE-3420-2C	2EG2 GEN. STATOR RTD	GREEN, BLACK	15
2-TE-3420-2D	2EG2 GEN. STATOR RTD	GREEN, BLACK	15
2-TE-3420-2E	2EG2 GEN. STATOR RTD	GREEN, BLACK	15
2-TE-3420-2F	2EG2 GEN. STATOR RTD	GREEN, BLACK	15

TABLE 8.3-10
ELECTRICAL EQUIPMENT NOT REQUIRING INTERNAL CABLE SEPARATION

(Sheet 10 of 11)

EQUIPMENT TAG NO.	DESCRIPTION	DIFFERENT COLOR-CODED CABLE WITHIN	NOTES
CP1-MEDGEE-01A	DIESEL GENERATOR 1-01 DIESEL ENGINE CONTROL PANEL		18
CP1-MEDGEE-02A	DIESEL GENERATOR 1-02 DIESEL ENGINE CONTROL PANEL		18
CP2-MEDGEE-01A	DIESEL GENERATOR 2-01 DIESEL ENGINE CONTROL PANEL		18
CP2-MEDGEE-02A	DIESEL GENERATOR 2-02 DIESEL ENGINE CONTROL PANEL		18

1. Separation is not required since they are integrally associated with each other.
2. Separation is not required since the associated circuit is integrally related to the non-Class 1E circuit and isolated by a Class 1E breaker tripped by an “S” signal.
3. Separation is not required since the Class 1E or the associated circuit is integrally related to the non-Class 1E circuit and isolated by two Class 1E breakers connected in series and coordinated with an upstream supply breaker (these three breakers are upstream of the portion of the circuit which does not require separation).
4. Separation between the identified associated circuits and black circuits is not required as these circuits carry low energy control signals.
5. Separation between the identified associated circuits and black circuits is not required as these circuits carry low energy instrumentation signals.
6. Equipment supplied by Westinghouse has been tested and is exempt from internal separation requirements (Reference FSAR Section 7.1.2.2).
7. Exemption from internal separation requirements does not apply to the field cables entering the input section of this cabinet.
8. Wiring of different trains/channels will be in different wire bundles, and will be separated to the maximum extent practicable (Reference FSAR Para. 8.3.1.2.1.7.C and SSER #1 Section 8.4.4).
9. Equipment supplied by Westinghouse has been analyzed and is exempt from internal separation requirements (Reference FSAR Section 7.1.2.2).
10. Equipment supplied by ITE has been analyzed and is exempt from internal separation requirements (Ref. FSAR Section 8.3.1.4.5).
11. Separation is not required since the manual transfer switches can only be aligned to Plant Support Power during Plant Modes 5 and 6 under procedural control. These procedures prevent 1E and non-class 1E power from being present at the transfer switch simultaneously.
12. Under all plant conditions connecting of non-class 1E cables from RCP circuits to class 1E PT input terminals does not degrade the PT ability to perform its function. The cables are fire retardant and routed in dedicated conduits which will preclude external non-class 1E cables-related fire damage to the PT cabinet. Hence in view of this, the PT cabinets are exempt from physical separation and also isolation is not required between non-class 1E cables and PT input fuse terminals.
13. Separation is not required because these associated circuits cannot be energized in modes 1 through 4 and never (in any mode) be energized at the same time.
14. Equipment supplied by FCI has been analyzed and is exempt from internal separation requirements (Reference FSAR Section 8.3)
15. Analysis indicates that connection of non-class 1E generator stator RTDs to 1E cables does not degrade the 1E circuit.

TABLE 8.3-10
ELECTRICAL EQUIPMENT NOT REQUIRING INTERNAL CABLE SEPARATION

(Sheet 11 of 11)

EQUIPMENT TAG NO.	DESCRIPTION	DIFFERENT COLOR-CODED CABLE WITHIN	NOTES

16. The separation between the output circuits of the spare inverters is accomplished by the procedural controls and interlocks. The procedural controls and the interlocks. The procedural controls and the interlocks ensure that only one output circuit cable from the spare inverter may be energized at a time. The remaining three output cables remain deenergized and disconnected at both ends thus eliminating the need for separation. Unit 2 spare inverters are not listed here as their input and output cables have the same classifications.

17. This equipment has been analyzed and is exempt from internal minimum separation distance between Class 1E and non-Class 1E cables. Component trips power to the personnel airlock hydraulic unit on SI signal. Power and control cabling are trained and secured to maximize spatial separation.

18. Equipment supplied by Delaval Engine & Compressor has been analyzed and is exempt from internal separation requirement. (Reference FSAR Section 8.3.1.4.5.)

TABLE 8.3-11
NON-CLASS 1E EQUIPMENT CONNECTED TO SAFETY RELATED POWER CIRCUITS

(Sheet 1 of 10)

EQUIPMENT ID NO.	DESCRIPTION	POWER SOURCE ID NO.		NOTE
CPX-CHCICE-03	HVAC CENTRIFUGAL WATER CHILLER #13	CP2-EPSWEA-01	14	(1)
CPX-CHCICE-01	HVAC CENTRIFUGAL WATER CHILLER #11	CP1-EPSWEA-01	4	(1)
CPX-CHCICE-04	HVAC CENTRIFUGAL WATER CHILLER #14	CP2-EPSWEA-02	11	(1)
CPX-CHCICE-02	HVAC CENTRIFUGAL WATER CHILLER #12	CP1-EPSWEA-02	7	(1)
CPX-EPMCNB-01	AUX BLDG NON SAFEGUARD MCC XEB1-3	CP1-EPSWEB-01	5B	(2)
CP1-EPMCNB-03	AUX, SG & FUEL BLDGS NON-SAFEGUARDS MCC 1EB1-3	CP1-EPSWEB-01	5D	(2)
CP1-EPMCNB-01	CONTAINMENT NON-SAFEGUARDS MCC 1EB1-2	CP1-EPSWEB-01	5C	(2)
CP1-VAFNAV-01	CONTAINMENT RECIRC FAN	CP1-EPSWEB-01	3B	(1)
TBX-CSAPPD-01	POSITIVE DISPLACEMENT CHARGING PUMP	CP1-EPSWEB-01	2B	(1)
CP1-EPTRNT-07	ISOL. TRANSFORMER FOR PRESSURIZER HTR CTRL GROUP-C	CP1-EPSWEB-01	6D	(1)
CP1-EPTRNT-05	ISOL. TRANSFORMER FOR PRESSURIZER HTR BK-UP GRP-A	CP1-EPSWEB-03	11B	(1)
CP1-VAFNAV-03	CONTAINMENT RECIRC FAN	CP1-EPSWEB-03	9B	(1)
CP1-VAFNCB-01	CRDM VENT FAN	CP1-EPSWEB-03	8B	(1)
CPX-EPMCNB-03	FUEL BLDG NON-SAFEGUARD MCC XEB3-1	CP1-EPSWEB-03	11C	(2)
CPX-FPAPFP-01	FIRE PUMP (FIRE BRIGADE TRAINING/EMERG FILL PUMP)	CP1-EPSWEB-03	9C	(7)
CP1-EPMCNB-04	AUX, SG & FUEL BLDGS NON-SAFEGUARD MCC 1EB2-3	CP1-EPSWEB-02	5D	(2)
CP1-EPMCNB-02	CONTAINMENT NON-SAFEGUARD MCC IEB2-2	CP1-EPSWEB-02	5C	(2)
CP1-VAFNAV-02	CONTAINMENT RECIRC FAN	CP1-EPSWEB-02	3B	(1)
CP1-EPDSNA-01	ALTERNATE POWER TRANSFER SWITCH	ALTERNATE POWER SOURCE		(10)
CP1-EPTRNT-06	ISOL. TRANSFORMER FOR PRESSURIZER HTR BK-UP GRP-B	CP1-EPSWEB-02	5B	(1)

TABLE 8.3-11
NON-CLASS 1E EQUIPMENT CONNECTED TO SAFETY RELATED POWER CIRCUITS

(Sheet 2 of 10)

EQUIPMENT ID NO.	DESCRIPTION	POWER SOURCE ID NO.		NOTE
CP1-EPTRNT-08	ISOL. TRANSFORMER FOR PRESSURIZER HTR BK-UP GRP-D	CP1-EPSWEB-04	11B	(1)
CP1-VAFNAV-04	CONTAINMENT RECIRC FAN	CP1-EPSWEB-04	9B	(1)
CP1-VAFNCB-02	CRDM VENT FAN	CP1-EPSWEB-04	8B	(1)
CPX-EMPCNB-04	FUEL BLDG NON-SAFEGUARD MCC XEB4-1	CP1-EPSWEB-04	11C	(2)
CP1-ELTRNT-26	LTG TRANSFORMER XFS1 POWER SUPPLY	CP1-EPMCEB-01	9E	(5)
CP1-EIPRLV-48	TURBINE DRIVEN AFW PUMP CONTROL PNL	CP1-EPMCEB-01	2KL	(1)
CP1-VAFNCB-03	POSITIVE DISPLACEMENT CHARGING PUMP ROOM FAN	CP1-EPMCEB-03	4F	(1)
CP1-CICACO-01	INSTRUMENT AIR COMPRESSOR 1-01	CP1-EPSWEB-03	11D	(1)
CP1-VAFNID-11	BATTERY ROOM 1-3 (C) EXHAUST FAN	CP1-EPMCEB-03	3C	(1)
MOV 1-8109	POSITIVE DISPLACEMENT PUMP BYPASS VALVE	CP1-EPMCEB-03	10J	(1)
CP1-CIDYIA-01	AIR DRYER CONTROL PANEL FDR	CP1-EPMCEB-03	2BR	(1)
CP1-EPTRNT-12 (T1C3)	BYPASS TRANSFORMER	CP1-EPMCEB-03	1CR	(1)
1-REK-5502/03/66	RADIATION MONITOR	CP1-EPMCEB-02	11D	(1)
CP1-ELTRNT-27	LTG TRANSFORMER XFS2 POWER SUPPLY	CP1-EPMCEB-02	10D	(5)
CP1-EPBCND-02	BATTERY CHARGER BC1D2 FOR BATTERY BT1D2	CP1-EPMCEB-02	1FR	(1)
CP1-VAFNID-12	BATTERY ROOM 1-3(C) EXHAUST FAN 12	CP1-EPMCEB-04	3C	(1)
CP1-EPBCND-04	BATTERY CHARGER BC1D4 FOR BATTERY BT1D4	CP1-EPMCEB-04	10DR	(1)
CP1-CICACO-02	INSTRUMENT AIR COMPRESSOR CONTROL PANEL	CP1-EPSWEB-04	11D	(1)
CP1-CIDYIA-02	INSTRUMENT AIR DRYER CONTROL PANEL	CP1-EPMCEB-04	12FL	(1)
CP1-VAFNAV-09	NEUTRON DETECTOR WELL FAN 09	CP1-EPMCEB-05	8M	(1)

TABLE 8.3-11
NON-CLASS 1E EQUIPMENT CONNECTED TO SAFETY RELATED POWER CIRCUITS

(Sheet 3 of 10)

EQUIPMENT ID NO.	DESCRIPTION	POWER SOURCE ID NO.		NOTE
CP1-ELTRNT-18	CONTAINMENT LTG TRANSFORMER/LTG PNLS SC1 & SC3	CP1-EPMCEB-05	7M	(5)
MOV 1-HV-6074	VENT CONTROL COOL UNIT COOLER/CHILLED WATER	CP1-EPMCEB-05	5G	(5)
MOV 1-HV-6076	VENT CONTROL COOL UNIT COOLER/CHILLED WATER	CP1-EPMCEB-05	4G	(5)
MOV 1-HV-6078	VENT CONTROL COOL UNIT COOLER/CHILLED WATER	CP1-EPMCEB-05	4M	(5)
CP1-EPTRNT-28	ISOL. TRANFORMER TIEC3-3	CP1-EPMCEB-05	1BR	(5)
CP1-ELTRNT-30	LTG TRANSFORMER XFS3	CP1-EPMCEB-06	4B	(5)
CP1-ELTRNT-31	LTG TRANSFORMER, PANEL S4	CP1-EPMCEB-07	1J	(5)
CP1-VAFNAV-10	NEUTRON DETECTOR WELL FAN 10	CP1-EPMCEB-06	7M	(1)
CP1-ELTRNT-19	CONTAINMENT LTG TRANSFORMER/LTG PNLS SC2 & SC4	CP1-EPMCEB-06	6M	(5)
MOV 1-HV-6075	VENT CONTROL COOL UNIT COOLER/CHILLED WATER	CP1-EPMCEB-06	4G	(5)
MOV 1-HV-6077	VENT CONTROL COOL UNIT COOLER/CHILLED WATER	CP1-EPMCEB-06	3G	(5)
MOV 1-HV-6079	VENT CONTROL COOL UNIT COOLER/CHILLED WATER	CP1-EPMCEB-06	3M	(5)
CP1-MEDGEE-02K	AUXILIARY JACKET WATER PUMP	CP1-EPMCEB-10	1M	(1)
CP1-MEDGEE-02J	AUXILIARY LUBE OIL PUMP	CP1-EPMCEB-10	3M	(1)
CP1-MEDGEE-02P	JACKET WATER HEATER	CP1-EPMCEB-10	4M	(1)
CP1-MEDGEE-02V	LUBE OIL HEATER	CP1-EPMCEB-10	2M	(1)
CP1-MECAED-03	DG AIR COMPRESSOR #3	CP1-EPMCEB-10	1G	(1)
CP1-MECAED-04	DG AIR COMPRESSOR #4	CP1-EPMCEB-10	2G	(1)
CP1-MEDGEE-02M	PRELUBE PUMP	CP1-EPMCEB-10	6M	(1)
CP1-MEDGEE-02L	JACKET WATER KEEP WARM PUMP	CP1-EPMCEB-10	7J	(1)

TABLE 8.3-11
NON-CLASS 1E EQUIPMENT CONNECTED TO SAFETY RELATED POWER CIRCUITS

(Sheet 4 of 10)

EQUIPMENT ID NO.	DESCRIPTION	POWER SOURCE ID NO.		NOTE
CP1-MEDGEE-02N	FUEL OIL BOOSTER PUMP	CP1-EPMCEB-10	7M	(1)
CP1-MEDGEE-02G	FUEL OIL DRIP RETURN PUMP	CP1-EPMCEB-10	8M	(1)
CP1-MECAED-03	COMPRESSOR AFTERCOOLER #3	CP1-EPMCEB-10	7C	(1)
CP1-MECAED-04	COMPRESSOR AFTERCOOLER #4	CP1-EPMCEB-10	8C	(1)
CP1-VAEHUH-30	ROOM ADJACENT TO REFUEL WATER STORAGE TANK HTR	CP1-EPMCEB-10	2BR	(1)
CP1-VAEHUH-28	ROOM ADJACENT TO REACTOR MK-UP WTR STORAGE TANK HTR	CP1-EPMCEB-10	4BL	(1)
CP1-VAEHUH-29	ROOM ADJACENT TO COND. WATER STORAGE TANK HTR	CP1-EPMCEB-10	4BR	(1)
CPX-CHAPCP-03	VENT CHILLED WATER PUMP 03	CPX-EPMCEB-01	3M	(1)
CPX-VAFNCB-09	PRIMARY PLANT VENT EXHAUST FAN 09	CPX-EPMCEB-01	4M	(7)
CPX-VAFNCB-11	PRIMARY PLANT VENT EXHAUST FAN 11	CPX-EPMCEB-01	5G	(7)
CPX-VAFNCB-13	PRIMARY PLANT VENT EXHAUST FAN 13	CPX-EPMCEB-01	5M	(7)
CPX-VAFNCB-03	CONTAINMENT HYDROGEN PURGE SUPPLY FAN 03	CPX-EPMCEB-01	3E	(1)
CPX-CHAPCP-04	VENT CHILLED WATER PUMP 4	CPX-EPMCEB-02	3M	(1)
CPX-VAFNCB-10	PRIMARY PLANT VENT EXHAUST FAN 10	CPX-EPMCEB-02	4M	(7)
CPX-VAFNCB-12	PRIMARY PLANT VENT EXHAUST FAN 12	CPX-EPMCEB-02	5G	(7)
CPX-VAFNCB-14	PRIMARY PLANT VENT EXHAUST FAN 14	CPX-EPMCEB-02	5M	(7)
CPX-VAFNCB-04	CONTAINMENT HYDROGEN PURGE SUPPLY FAN 04	CPX-EPMCEB-02	3E	(1)
CPX-EPTRNT-43	AUX BLDG REGULATING TRANSFORMER TXEC2	CPX-EPMCEB-02	5BR	(5)
CPX-CHAPCP-01	VENT CHILLED WATER PUMP 1	CPX-EPMCEB-07	4M	(1)
CPX-VAFNAV-27	AUXILIARY BLDG VENT EQUIP ROOM EXHAUST FAN 27	CPX-EPMCEB-07	3M	(1)

TABLE 8.3-11
NON-CLASS 1E EQUIPMENT CONNECTED TO SAFETY RELATED POWER CIRCUITS

(Sheet 5 of 10)

EQUIPMENT ID NO.	DESCRIPTION	POWER SOURCE ID NO.		NOTE
CPX-EPTRNT-44	REGULATING TRANSFORMER TXEC3	CPX-EPMCEB-07	1BR	(5)
CPX-EPTRNT-42	REGULATING TRANSFORMER TXEC1	CPX-EPMCEB-03	7DR	(5)
CPX-CHAPCP-02	VENT CHILLED WATER PUMP 2	CPX-EPMCEB-08	3M	(1)
CPX-VAFNAV-28	AUXILIARY BLDG VENT EQUIP ROOM EXHAUST FAN 28	CPX-EPMCEB-08	4M	(1)
X-REK-5567A	VENT STACK “1” RADIATION MONITOR SYS SAMPLE PUMP	CPX-EPMCEB-03	6C	(1)
CPX-VAFNCB-15	PRIMARY PLANT VENT EXHAUST FAN 15	CPX-EPMCEB-03	4G	(7)
CPX-VAFNCB-17	PRIMARY PLANT VENT EXHAUST FAN 17	CPX-EPMCEB-03	4M	(7)
CPX-VAFNCB-19	PRIMARY PLANT VENT EXHAUST FAN 19	CPX-EPMCEB-03	5G	(7)
CPX-CHCICE-01	HVAC CENTRIFUGAL WATER CHILLER OIL PUMP	CPX-EPMCEB-03	5BL	(5)
CPX-CHCICE-03	HVAC CENTRIFUGAL WATER CHILLER OIL PUMP	CPX-EPMCEB-07	5BL	(5)
X-REK-5567B	VENT STACK “2” RADIATION MONITOR SYS SAMPLE PUMP	CPX-EPMCEB-04	6G	(1)
CPX-VAFNCB-16	PRIMARY PLANT VENT EXHAUST FAN 16	CPX-EPMCEB-04	4G	(7)
CPX-VAFNCB-18	PRIMARY PLANT VENT EXHAUST FAN 18	CPX-EPMCEB-04	4M	(7)
CPX-VAFNCB-20	PRIMARY PLANT VENT EXHAUST FAN 20	CPX-EPMCEB-04	5G	(7)
CPX-EPTRNT-45	REGULATING TRANSFORMER TXEC4	CPX-EPMCEB-04	7C	(5)
CPX-CHCICE-02	HVAC CENTRIFUGAL WATER CHILLER OIL PUMP	CPX-EPMCEB-04	5BL	(5)
CPX-CHCICE-04	HVAC CENTRIFUGAL WATER CHILLER OIL PUMP	CPX-EPMCEB-08	2BR	(5)
CP1-MEDGEE-01M	PRELUBE PUMP	CP1-EPMCEB-09	6M	(1)
CP1-MEDGEE-01L	JACKET WATER KEEP WARM PUMP	CP1-EPMCEB-09	7J	(1)
CP1-MEDGEE-O1N	FUEL OIL BOOSTER PUMP	CP1-EPMCEB-09	7M	(1)

TABLE 8.3-11
NON-CLASS 1E EQUIPMENT CONNECTED TO SAFETY RELATED POWER CIRCUITS

(Sheet 6 of 10)

EQUIPMENT ID NO.	DESCRIPTION	POWER SOURCE ID NO.		NOTE
CP1-MEDGEE-01G	FUEL OIL DRIP RETURN PUMP	CP1-EPMCEB-09	8M	(1)
CP1-MECAED-01	COMPRESSOR AFTERCOOLER 1	CP1-EPMCEB-09	7C	(1)
CP1-MECAED-02	COMPRESSOR AFTERCOOLER 2	CP1-EPMCEB-09	8C	(1)
CP1-VAEHUH-27	RM ADJ TO REFUEL WATER STORAGE TANK HTR	CP1-EPMCEB-09	2BR	(1)
CP1-VAEHUH-25	RM ADJ TO REACTOR MK-UP WATER STORAGE TANK HTR	CP1-EPMCEB-09	4BL	(1)
CP1-VAEHUH-26	RM ADJ TO COND. WATER STORAGE TANK HTR	CP1-EPMCEB-09	4BR	(1)
CP1-MEDGEE-01K	AUXILIARY JACKET WATER PUMP	CP1-EPMCEB-09	1M	(1)
CP1-MEDGEE-01J	AUXILIARY LUBE OIL PUMP	CP1-EPMCEB-09	3M	(1)
CP1-MEDGEE-01P	JACKET WATER HEATER	CP1-EPMCEB-09	2M	(1)
CP1-MEDGEE-01V	LUBE OIL HEATER	CP1-EPMCEB-09	4M	(1)
CP1-MECAED-01	DG AIR COMPRESSOR #1	CP1-EPMCEB-09	1G	(1)
CP1-MECAED-02	DG AIR COMPRESSOR #2	CP1-EPMCEB-09	2G	(1)
CPX-EPMCEB-05	MOTOR CONTROL CENTER XEB3-3	CP2-EPMCEB-07	2M	(4)
CPX-EPMCEB-05	MOTOR CONTROL CENTER XEB3-3	CP1-EPMCEB-07	2E	(4)
CPX-SWTSTS-01	SERVICE WATER TRAVELING SCREEN	CPX-EPMCEB-05	3C	(4)
CP1-SWAPTS-01	SERVICE WATER SCREEN WASH PUMP	CPX-EPMCEB-05	3F	(4)
CPX-ELTRNT-36	LIGHTING TRANSFORMER (LTG PNL SWP1)	CPX-EPMCEB-05	3HL	(4)
WRCPT2	WELDING RECEPTACLE	CPX-EPMCEB-05	1L	(3)
CPX-MESCSW-01	SERVICE WATER INTAKE STRUCTURE CRANE	CPX-EPMCEB-05	1FL	(3)
CPX-VAEHUH-08	SERVICE WATER PUMPHOUSE UNIT HEATER 08	CPX-EPMCEB-05	1FR	(3)

TABLE 8.3-11
NON-CLASS 1E EQUIPMENT CONNECTED TO SAFETY RELATED POWER CIRCUITS

(Sheet 7 of 10)

EQUIPMENT ID NO.	DESCRIPTION	POWER SOURCE ID NO.		NOTE
CPX-MEMHCH-12	SERVICE WATER TRAVELING SCREEN HOIST	CPX-EPMCEB-05	1BL	(3)
CPX-VAEHUH-06	SERVICE WATER PUMPHOUSE UNIT HEATER 06	CPX-EPMCEB-05	1BR	(3)
CPX-VAEHUH-09	SERVICE WATER PUMPHOUSE UNIT HEATER 09	CPX-EPMCEB-05	1DL	(3)
CPX-RUDMSW-01	ROLL UP DOOR	CPX-EPMCEB-05	1DR	(3)
CPX-ELTRNT-37	LIGHTING TRANSFORMER (LTG PNL SWP2)	CPX-EPMCEB-06	2HL	(4)
CPX-VAFNAV-41	DIESEL FIRE PUMP ROOM VENTILATION EXH FAN 41	CPX-EPMCEB-06	5F	(3)
CPX-SWEHSG-01	SCREEN STOP GATE HOIST (2HP)	CPX-EPMCEB-06	5MR	(3)
WRCPT1	WELDING RECEPTACLE (60 AMPS)	CPX-EPMCEB-06	4L	(3)
CPX-ELTRNT-02	SWIS CHLOR. BLDG DIST TRANSFORMER (LTG PNL SWN1&SWCB1)	CPX-EPMCEB-06	4BL	(3)
CPX-VAEHUH-04	SERVICE WATER PUMPHOUSE UNIT HEATER 04	CPX-EPMCEB-06	4BR	(3)
CPX-VAEHUH-05	SERVICE WATER PUMPHOUSE UNIT HEATER 05	CPX-EPMCEB-06	4DL	(3)
CPX-ECCPRT-05	SWIS CATHODIC PROTECTION RECTIFIER #5	CPX-EPMCEB-06	4DR	(3)
CPX-EPTRNT-21	HEAT TRACING TRANSFORMER TXHT-2 (HT DIST PNL XHT-2)	CPX-EPMCEB-06	4FL	(3)
CPX-VAEHUH-07	SERVICE WATER PUMPHOUSE UNIT HEATER 07	CPX-EPMCEB-06	4FR	(3)
CPX-EPMCEB-06	MOTOR CONTROL CENTER XEB4-3	CP2-EPMCEB-08	2M	(4)
CPX-EPMCEB-06	MOTOR CONTROL CENTER XEB4-3	CP1-EPMCEB-08	2E	(4)
CPX-SWTSTS-02	SERVICE WATER TRAVELING SCREEN 02	CPX-EPMCEB-06	2C	(4)
CPX-SWAPTS-02	SERVICE WATER SCREEN WASH PUMP 02	CPX-EPMCEB-06	2F	(4)
CPX-FPAPFP-03	JOCKEY FIRE PUMP	CPX-EPMCEB-06	3C	(4)
CP1-ELTRET-01	XFMR FOR LTG DIST PNL ESB1 & ESB3	CP1-EPMCEB-01	1DL	(5),(6)

TABLE 8.3-11
NON-CLASS 1E EQUIPMENT CONNECTED TO SAFETY RELATED POWER CIRCUITS

(Sheet 8 of 10)

EQUIPMENT ID NO.	DESCRIPTION	POWER SOURCE ID NO.		NOTE
CP1-ELTRET-02	XFMR FOR LTG DIST PNL ESB5, ESB7, ESB9 & ESBD-1	CP1-EPMCEB-01	1DR	(5),(6)
CP1-ELTRET-03	XFMR FOR LTG DIST PNL ESB2 & ESB4	CP1-EPMCEB-02	1BL	(5),(6)
CP1-ELTRET-04	XFMR FOR LTG DIST PNL ESB6, ESB8, ESB10 & ESBD-2	CP1-EPMCEB-02	1BR	(5),(6)
CPX-ELTRET-09	XFMR FOR LTG DIST PNL EAB5, EAB7 & EABD-3	CPX-EPMCEB-01	4BL	(5),(6)
1EB1-1/8M/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CP1-EPMCEB-01	8M	(1)
1EB3-1/9M/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CP1-EPMCEB-03	9M	(1)
1EB2-1/10M/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CP1-EPMCEB-02	10M	(1)
1EB4-1/11M/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CP1-EPMCEB-04	11M	(1)
1EB3-2/7C/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CP1- EPMCEB-05	7C	(1)
1EB4-2/6C/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CP1-EPMCEB-06	6C	(1)
1EB4-4/8J/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CP1-EPMCEB-10	8J	(1)
XEB1-2/6M/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CPX-EPMCEB-01	6M	(1)
XEB2-2/6M/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CPX-EPMCEB-02	6M	(1)
XEB1-1/2M/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CPX-EPMCEB-07	2M	(1)
XEB2-1/5M/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CPX-EPMCEB-08	5M	(1)
XEB3-2/2F/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CPX-EPMCEB-03	2F	(1)
XEB4-2/2F/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CPX-EPMCEB-04	2F	(1)
1EB3-3/3M/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CP1-EPMCEB-07	3M	(1)
1EB3-4/8J/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CP1-EPMCEB-09	8J	(1)
1EB4-3/3M/TR	MCC AND MOTOR SPACE HEATER SUPPLY	CP1-EPMCEB-08	3M	(1)

TABLE 8.3-11
NON-CLASS 1E EQUIPMENT CONNECTED TO SAFETY RELATED POWER CIRCUITS

(Sheet 9 of 10)

EQUIPMENT ID NO.	DESCRIPTION	POWER SOURCE ID NO.		NOTE
CPX-ELTRET-06	XFMR FOR LTG DIST PNL ECB2 & EAB10	CPX-EPMCEB-02	6C	(5),(6)
CPX-ELTRET-10	XFMR FOR LTG DIST PNL EABD4, EAB6 & EAB8	CPX-EPMCEB-02	4BL	(5),(6)
CP1-ELTRET-05	XFMR FOR LTG DIST PNL ECB5 & ECB3	CP1-EPMCEB-07	5BL	(5),(6)
CP2-ELTRET-05	XFMR FOR LTG DIST PNL 2ECB3	CPX-EPMCEB-07	5BR	(5),(6)
CPX-ELTRET-05	XFMR FOR LTG DIST PNL EAB9 & ECB1	CPX-EPMCEB-07	1BL	(5),(6)
CP2-ELTRET-06	XFMR FOR LTG DIST PNL 2ECB4	CPX-EPMCEB-08	2BL	(5),(6)
CP1-ELTRET-06	XFMR FOR LTG DIST PNL ECB4 & ECB6	CPX-EPMCEB-08	2BR	(5),(6)
CPX-ELTRET-07	XFMR FOR LTG DIST PNL EAB1, EAB3, EAB11 & EABD1	CPX-EPMCEB-03	4BL	(5),(6)
CPX-ELTRET-08	XFMR FOR LTG DIST PNL EAB2, EAB4, EAB12 & EABD2	CPX-EPMCEB-04	6A	(5),(6)
CP1-MEDGEE-01H	GENERATOR SPACE HEATER	CP1-EPMCEB-09	2BL	(8)
CP1-MEDGEE-02H	GENERATOR SPACE HEATER	CP1-EPMCEB-10	2BL	(8)
CPX-VAFNCB-01	Hydrogen Purge System (HPS) Exhaust Fan 01	CPX-EPMCEB-01	6J	(1)
CPX-VAFNCB-02	Hydrogen Purge System (HPS) Exhaust Fan 02	CPX-EPMCEB-02	6J	(1)
CPX-VAFUPK-19	HPS Filtration Unit Heaters 19	CPX-EPMCEB-01	2BR	(1)
CPX-VAFUPK-20	HPS Filtration Unit Heaters 20	CPX-EPMCEB-02	2BR	(1)
CPX-VAFULV-19	Fire Protection Panel 19	CPX-ECDPEC-03	9	(5)
CPX-VAFULV-20	Fire Protection Panel 20	CPX-ECDPEC-04	9	(5)
X-HV-5526	HPS Motorized Valve	CPX-EPMCEB-03	2C	(5)
X-HV-5579	HPS Motorized Valve	CPX-EPMCEB-03	6F	(5)

TABLE 8.3-11
NON-CLASS 1E EQUIPMENT CONNECTED TO SAFETY RELATED POWER CIRCUITS

(Sheet 10 of 10)

EQUIPMENT ID NO.	DESCRIPTION	POWER SOURCE ID NO.		NOTE
X-HV-5529	HPS Motorized Valve	CPX-EPMCEB-04	2C	(5)
X-HV-5580	HPS Motorized Valve	CPX-EPMCEB-04	6D	(5)
CP2-CICACO-01	INSTRUMENT AIR COMPRESSOR 2-01	CP2-EPSWEB-03	10C	(1)
CP2-CICACO-02	INSTRUMENT AIR COMPRESSOR 2-02	CP2-EPSWEB-04	10D	(1)
CP2-CIDYIA-01	INSTRUMENT AIR DRYER 2-01	CP2-EPMCEB-03	2BR	(1)
CP2-CIDYIA-02	INSTRUMENT AIR DRYER 2-02	CP2-EPMCEB-06	9FL	(1)

NOTES:

(1) In accordance with Regulatory Guide 1.75, January 1975, Position C.1, Automatically Tripped on SIAS (accident signal). Reconnection requires operator action(s) after resetting SIAS.

(2) Breaker trips on SIAS, requires operator action to reset, and connecting cable is black and routed separately. In addition, these loads are also tripped on LOOP.

(3) This portion of the non-Class 1E MCC is tripped on SIAS or Blackout (Loss of Offsite Power) signal, and cable is in dedicated raceway.

(4) Same as No. 1, except MCC's are tripped from either Unit 1 or 2 independent power supply, thus MCC's, associated and non-Class 1E loads are isolated by SIAS signal. During normal operation MCC's are powered by Unit 2, and Unit 1 power is locked out.

(5) Non-Class 1E loads fed from Class 1E supplies are protected by two separate Class 1E breakers, or Class 1E breaker and Class 1E fuse or two separate Class 1E fuses connected in series. These breakers/fuses are coordinated with their supply breakers, and breakers will be tested and calibrated periodically to ensure coordination.

(6) The Class 1E transformers and lighting distribution panels feed non-Class 1E loads.

(7) Breaker trips on SIAS (accident signal), reconnection requires operator action to reset, and connecting cable is associated. In addition, this load is also tripped on LOOP.

(8) Breaker trips on SIAS, requires operator action to reset, and connecting cable is black and routed separately. These loads are also tripped by diesel generator breaker auxiliary contacts when the breaker closes to power the Class 1E bus. Therefore the loads will not be on the bus during a safety injection or loss of offsite power.

(9) Equipment listed, is for Unit 1; Unit 2 is similar, except for equipment identification numbers.

(10) Transfer switch is isolated from Class 1E bus by administratively controlled normally open circuit breakers. There are no automatic connections to the 1E bus. It is only connected to either bus during modes 5 and 6, and only if the plant experiences a loss of offsite power coincident with failure of the Class 1E Emergency Diesel Generators

8A ANALYSIS TO JUSTIFY CABLE SPLICES IN RACEWAYS

8A.1 PURPOSE

The purpose of this analysis is to show that the limited use of splices in raceways, incorporated in the CPNPP design, does not degrade the Class 1E circuits and does not pose any undue hazard of a fire. This analysis is developed to satisfy the requirements of NRC Regulatory Guide 1.75, Rev. 1, Regulatory Position C.9.

8A.2 SCOPE

This analysis covers all cable splices in raceways utilized in the CPNPP plant design. The term "raceways" shall include open or enclosed trays and rigid or flexible steel conduits and condulets. This analysis does not discuss splices inside an equipment enclosure, splices in junction/terminal boxes furnished as an integral part of an equipment, or splices in junction/terminal boxes in raceways, since the purpose of such boxes is the termination of cables. This analysis does not discuss splices in yard non-Class I (non-seismic) manholes and handholes since these manholes/handholes do not contain and are not in the vicinity of Class 1E cables and equipment. Splices in Class I (seismic) manholes containing Class 1E cables are not discussed since one of the purposes of manholes is to accommodate splices and individual manholes do not contain cables of opposite trains.

Although this analysis covers cable splices in raceways, the description provided also applies to other Class 1E splices performed at CPNPP.

In CPNPP cable splices which are made in raceways can be categorized in the following three groups:

1. Group 1 - Field routed power, control and instrumentation cables which are connected to pigtail cables from Electric Penetration Assembly (EPA) and Core Exit Thermocouple (CET) Integral Reference Junction (IRJ), Control Rod Drive Mechanism (CRDM) disconnect panel connectors and Electric Conductor Seal Assemblies (ECSAs) pigtail cables by means of in-line splices located in trays.

2. Group 2 - Pigtail cables from local mounted devices (LMDs - solenoid valves, limit switches, level switches, etc.) which are connected to field routed control and instrument grade cables by means of parallel or in-line butt splices located in flexible conduit or condulets.

3. Group 3 - Pigtail cables from local mounted devices which are connected to the pigtail conductors of the Electric Conductor Seal Assembly (ECSA) by means of in-line butt splices located in the flexible conduit of the ECSA.

8A.3 REGULATORY POSITION REQUIREMENT

The CPNPP FSAR commits to IEEE Std. 384-1974 and NRC Regulatory Guide 1.75, Revision 1 dated January 1975. Section 5.1.1.3 of IEEE Standard 384, with the Regulatory Guide 1.75, Regulatory Position C.9 supplement, reads as follows:

"5.1.1.3 The minimum separation distances specified in Section 5.1.3 and 5.1.4 are based on open ventilated cable trays of either the ladder or trough type as defined in NEMA VE1-1971, Cable Tray Systems. Where these distances are used to provide adequate physical separation:

(1) Cables and raceways involved shall be flame retardant

(2) The design basis shall be that the cable trays will not be filled above the side rails

(3) Hazards shall be limited to failures or faults internal to the electric equipment or cables

(4) Cable splices in raceways should be prohibited.

If lesser separation distances are used they shall be established as in Section 5.1.1.2."

In plant areas where hazards are limited to failures or faults internal to the electric equipment or cables, CPNPP design permits the minimum separation distances specified in Sections 5.1.3 and 5.1.4 of the IEEE Standard 384 to achieve independence between redundant trains. Use of these specified separation distances in plant design therefore requires compliance with all of the above conditions unless justified by analysis.

Per requirement 3 above, hazards are limited to failures or faults internal to the electric equipment or cables. For this analysis then, the only hazard of concern would be an electrically generated fire inside the raceway.

Regulatory Position C.9 prohibits splices in raceways even though separation distance is adequate to prevent a fire in the raceways of one train from affecting cables in a redundant train. However, it also states under the "Basis" of this position (paragraph C.9) that "Splices are not, by themselves, unacceptable. If they exist, the resulting design should be justified by analyses." Use of splices in raceways must therefore be justified. For this analysis, it will be shown that (1) the minimum separation distances utilized in the plant design is adequate to maintain independence between redundant trains for a postulated fire originating at a cable splice and (2) cable splices in raceways do not pose any undue hazard of initiating a fire.

8A.4 DETERMINATION OF ACCEPTABILITY OF CABLE SPLICES IN RACEWAYS

8A.4.1 INDEPENDENCE OF REDUNDANT TRAINS

Minimum separation distances utilized in CPNPP design to achieve independence between redundant trains meet the requirements of Sections 5.1.3 and 5.1.4 of IEEE Standard 384. Per the requirements of IEEE Standard 384, as modified by Regulatory Guide 1.75, these minimum separation distances are adequate provided (1) cable and raceway materials involved are flame retardant, (2) cable trays are not filled above their side rails, (3) hazards are limited to fire originating in the raceway and (4) there should be no cable splices in raceways.

Since the design may not comply with the fourth requirement, the question would be whether the specified minimum separation distances are adequate for providing independence between redundant trains in case of a fire electrically generated at a cable splice.

Where there are no splices, the specified separation distances per the Standard, or as allowed by tests or analysis, are adequate to satisfy this objective for the case of an electrically generated cable fire. If the fire generated at a cable splice is no worse than a cable fire, the specified minimum separation distances would be adequate. We will show that the degree of potential damage from a cable splice fire is no more than the degree of potential damage from a fire in a cable without splices.

All cable splices within the scope of this analysis are made of essentially two types of material: one is the metallic connector part for conducting current and the second is the non-metallic insulation part. The metallic part is non-combustible like the copper conductor in a cable. The insulation materials applied at the splice are of a flame retardant type similar to the insulation and jacket material of a cable.

The insulation and jacket materials of CPNPP cables in raceways consist of EPR, XLPE, CPE, ETFE and CSPE. The materials, in their constructed configurations, are flame retardant and are self extinguishing. This has been shown by documented tests performed by the cable vendors in order to qualify their cables per Section 2.5 test requirements of IEEE Standard 383-1974. The oxygen index of these cable insulating materials ranges from 22 to 34. The higher the oxygen index, the quicker the fire extinguishes. Uninsulated splices employ Raychem heat-shrink type insulating material or Okonite tape. Insulated splices use AMP PIDG and Pre-Insulated Environmental Splices (PIES) connectors with PVF2 (Kynar) insulation material. The materials involved in the Raychem splices consist of WCSF for sleeves, "-52" for molded parts and S-1119 used as a sealant and adhesive. WCSF has passed the IEEE Standard 383 flame test. The -52 material is a cross-linked Polyolefin similar to WCSF and has the same oxygen index of 28. Therefore a similar performance to WCSF is expected. S-1119 adhesive has also passed the flame test with WCSF. In the installed configuration, the major portion of the S-1119 material does not have access to air. Access to air is esential for a burning process to continue. The oxygen index of Kynar is 44. The oxygen index of the remaining non-metallic splice products ranges from 28-44, which is higher than the minimum oxygen index of the cable insulation and jacket materials. The Okonite jacketing and insulation tapes have successfully passed the IEEE Standard 383 flame test in the installed configuration. Therefore, it can be seen that all cable splices, as installed, are flame retardant, non-propagating and self-extinguishing to a degree equal to or greater than the cable insulating material itself.

Based on the above, it is concluded that the degree of potential damage due to a fire at a cable splice is no more than that from a fire in a cable. Therefore, use of the minimum required separation distances specified in Sections 5.1.3 and 5.1.4 of IEEE Standard 384-1974 is justified for the splices utilized in the CPNPP design.

8A.4.2 ASSESSMENT OF FIRE HAZARD DUE TO CABLE SPLICES IN RACEWAYS

8A.4.2.1 Approach

In Section 4.1 of this analysis we have shown that the consequences of a postulated fire originating at a cable splice are acceptable. In this Section we will show that the likelihood of such a postulated fire in a splice is no greater than that in a cable itself.

A fire can originate in the insulating materials of a cable splice due to (1) excessive heating of the internal current-carrying metallic parts and (2) breakdown of the dielectric property of the insulating material. In order to assess the probability of such a fire, we need to evaluate the

control of splices which have been used in raceways and those attributes which can cause such heating and dielectric breakdown.

The purpose of this analysis is not to prove that a cable splice would not generate a fire under any circumstances. The attributes which have the potential of starting a fire in a cable (e.g., failure of a circuit protective device to interrupt a fault current) may also start a fire at a cable splice. What will be shown is that introduction of a good quality cable splice (installed using approved procedures by trained personnel using approved materials) in a continuous cable run does not create a weak link; that is, it is at least as reliable as the continuous cable run. We will therefore analyze all the attributes of a splice which are essential to ensure that consistently good quality splices are provided in the CPNPP design and construction.

8A.4.2.2 Review of Attributes and Their Effects

1. Attribute: Limited and controlled use of splices.

   Discussion: The electrical erection specification, used for construction of CPNPP, requires that cables be installed without splices unless splices are specifically called for on the drawings, cable and raceway schedule, or when approved by the Engineer. All splices in CPNPP are made per the electrical drawings. These drawings show typical details for each group of splices. The details identify the materials to be used to make field splices. Per procedures, the Engineer's approval of design changes is recorded via Design Change Authorizations. These procedures ensure application of quality control for site performed splices.

2. Attribute: Quality assurance and quality control.

   Discussion: All materials involved in the splice connections are procured under the quality assurance program in compliance with the applicable ANSI N45.2 series of standards. Splices are made only by trained personnel as per the installation procedures. This procedure ensures adherence to splice manufacturer's recommended methods for installation and all construction drawings and specifications.

   Use of the proper compression tool is assured since all AMP tools are matched by design to specific connectors. The tools are serialized and periodically checked for calibration by the on- site calibration laboratory. The tools are of the ratchet type and each crimp is brought to a full compression before the tool can be released. This ensures compliance with the manufacturer's crimping requirement and excludes any possibility of an under or over crimp condition. The tools are logged in and out of a tool room each day and are checked with a "go/no go" gauge at the end of each day. The craftsman records on the tool card the use made of the tool on each occasion. Tools that do not pass the "go/no go" test are taken out of service and the connectors installed with them that day are removed.

   All Class 1E splices are inspected in accordance with quality control procedures and each splice inspection is documented by an inspection report. QC inspects all physical attributes that make up the splice, e.g., selection of proper connector and crimping tool, proper stripping of cable insulation and jacket, proper insertion of conductor into the connector barrel, adequacy of crimp, etc. If a bolted connection is being made, QC verifies correct bolting materials and witnesses torquing. For splices which are insulated

at site by installation of heat shrink tubing, QC verifies proper cleaning of cable, proper selection of heat shrink material and proper installation. All these steps ensure that the splices are made per manufacturers' installation procedures and thereby produce qualified high quality splices. The QC inspection reports and the cable connection sign-off cards are maintained as a permanent QA record. Non-Class 1E splices are installed under craft supervision in accordance with approved procedures, using attributes similar to the Class 1E splice attributes.

The above shows that adequate quality assurance and control measures are implemented to ensure a good quality splice.

3. Attribute: Effect of temperature on splice materials.

Discussion: All CPNPP splices utilize either insulated or uninsulated type connectors. All splice connectors are made of fine grade high conductivity copper and have tin plating to resist corrosion. The connectors are crimped on the cable conductors by using calibrated compression tools which give positive indication of completion of compression. The compression tooling has features to prevent under or over crimping and provides dot or wire size coding for quality control verification.

The AMP PIDG and PIES connectors meet the requirements of MIL-T-7928. Their use is restricted to #10 AWG size cable and smaller. All other wire connectors utilized in CPNPP are UL 486A Listed and all splicing wire connectors are UL 486C Listed. As part of the UL Listing requirements, the connectors must pass the static heating test. The maximum acceptable temperature rise when tested with UL specified currents is 50 deg. C. Table A below shows the UL specified test current and maximum design limit currents utilized in CPNPP design for different conductor sizes.

TABLE A

Conductor Size	UL Static Heating Specified Test Current-Amp UL 486A	UL 486C	CPS ES Maximum Design Limit Current-Amp
# 12 AWG	35	35	25
# 10 AWG	50	50	33
# 8 AWG	70	70	46
# 6 AWG	95	95	62
# 4 AWG	125	-	81
# 2 AWG	170	-	116
# 2/0AWG	265	-	182
# 4/0AWG	360	-	249
350 MCM	505	-	405

500 MCM	620	-	509
750 MCM	785	-	658

From Table A above, it can be seen that the UL specified test currents which can produce a maximum 50 deg. C connector temperature rise are 119 to 154 percent higher than the maximum CPNPP design limit currents. The IEEE 323 qualification test for AMP preinsulated splice connectors has shown a maximum temperature rise of 37.7 deg. C during the post-radiation and LOCA static heating test with UL specified test currents. Therefore the connector temperature rise for CPNPP will be much less than 40 deg. C, which is the design limit temperature rise for CPNPP cables.

All insulating materials applied at the splices (i.e., Raychem WCSF and "-52", AMP Kynar materials, and Okonite tapes) have a demonstrated 40 year qualified life at 90 deg. C operating temperature, which is the minimum rated insulation temperature of CPNPP cables.

Therefore, it is concluded that the conducting material of the splices, which operate at a lower temperature than the conductor, are not hot spots which can degrade the insulating materials.

4. Attribute: Aging of splice insulating materials.

Discussion: The insulation materials utilized for uninsulated connectors are Raychem WCSF or "-52" material. The AMP preinsulated splice connectors have PVF2 Kynar insulation. All splices are made using material manufacturers' procedures.

The manufacturers have qualified the splice configurations (recommended in their procedures) per requirements of IEEE Standards 323 and 383. The splices were thermally aged to simulate a 40 year installed life using Arrhenius methodology. The DBE testings included vibration and LOCA exposure. The qualification tests have demonstrated that all splices in raceways are capable of performing their required functions throughout their 40 year qualified life and during Design Basis Events of seismic, radiation exposure, LOCA and post-LOCA conditions, as applicable (PIES are used only in mild environment areas). Therefore, aging of the splices will not create a weak link in the cable run.

Selected Class 1E splices not in raceways, for high voltage applications outside containment, may have a shorter qualified life and will be replaced prior to expiration of their qualified life.

5. Attribute: Mechanical integrity.

Discussion: Splicing wire connectors (in-line butt type or parallel connectors) or wire connectors (bolted back to back solid tongue (with hole(s)) type lugs) are used for making splice connections. The connectors are crimped on the cable conductors by using manufacturer's certified compression tools. Bolted joints are torqued to the values specified in the installation procedures. The splicing wire connections are capable of withstanding the UL 486C pull-out test requirements and the wire connections (bolted

tongue connections) are capable of withstanding the UL 486A pull-out test requirements. The AMP PIDG and PIES connectors meet MIL-T-7928 pull out test requirements which are more severe than UL 486A and UL 486C. Additionally, splices at terminations can only be made after the cables are pulled. Thus, pulling stresses which have potential to degrade the splices are eliminated. Hence, mechanical integrity of CPNPP splices will not be degraded during or after installation.

8A.5 SUMMARY AND CONCLUSION

It has been shown that the splice materials, tools, qualification, drawings, training and installation procedures used at CPNPP are designed to ensure that all splices made will be of high quality. Limited use of splices in raceways in the CPNPP design does not compromise independence of redundant Class 1E trains nor significantly increase the likelihood of fire. As such, splices, as applied, do not pose any undue hazard nor do they introduce weak links in the cable run and they can be expected to function at least as good as the continuous cable in which they are installed. Therefore, the CPNPP design meets the intent of the Regulatory Guide 1.75, Regulatory Position C.9.

8B STATION BLACKOUT

To assess the compliance of Comanche Peak Units 1 and 2 with the Station Blackout rule (10CFR50.63) an evaluation [Ref.2] following the guidance provided by RG 1.155 [Ref.1] was performed. This evaluation determined that both units are capable of coping with a station blackout (SBO) for 4 hours as AC Independent plants and that no modifications were required.

Subsequent SBO evaluations and other clarifications of sections of Attachment 1 to Ref.2 are as follows:

1. Section A.3.3: An EDG on the Non-SBO unit will energize on the loss of offsite power and provide power to common equipment in support of the SBO unit; however, as this is a normal electrical line up, it does not constitute the “Alternate AC” approach to coping with SBO.

2. Sections A.4.2 and D.3.12: Although they are assumed to function normally, no credit for SBO coping is required for the non-safety related turbine stop valves, feedwater control valves or feedwater control bypass valves. The safety related main steam and feedwater isolation valves do not require AC power to close.

3. Section A.4.2: Steam generator blowdown and sampling valves close on a loss of air or power.

4. Section A.4.3: The pressurizer PORVs should not cycle during an SBO. They are environmentally qualified to not fail open in an adverse environment.

5. Section A.10: Containment isolation valves on the secondary side of the steam generators are excluded from those of concern by Ref. 3. Closure of these valves for containment isolation during SBO coping is not required.

6. Section E.3: Air operated valves that are needed for SBO can be initially operated remotely with air stored in accumulators and locally manually when air is exhausted. The air accumulators for the Atmospheric Relief Valves (ARVs) on the steam generators are sized for Steam Generator Tube Rupture Mitigation as described in Section 9.3.1.2 and are not required to provide air for the entire SBO duration.

7. Section F.b: NUMARC 87-00 [Ref. 3] considers it necessary for plants, such as CPNPP, to further analyze control room air conditioning if it is a common control room with partial operational capability remaining during the SBO scenario.

8. Section F.c: Modifications to the UPS equipment and ventilation systems have been made which enhance SBO coping. Equipment qualification limitations have been increased from 120°F by replacement with inverters which have a 131°F limit. Ventilation modifications are described in References 4 and 5 and in FSAR Section 9.4C.8

The 4-hour coping duration was determined by approved methods based on the redundancy and reliability of onsite emergency AC power sources, the expected frequency of loss of offsite power, and the probable time needed to restore offsite power.

The reactor coolant system with associated support systems were analyzed and determined to be capable of maintaining the appropriate core cooling and containment integrity during a 4-hour postulated SBO event.

The analysis ensured that the applicable emergency response guidelines facilitate proper monitoring of plant parameters and mitigation of the SBO effects.

Because CPNPP Units 1 and 2 have certain common cooling systems, the evaluation showed that no equipment modifications were required for a blacked out unit to cope with a Station Blackout event.

SBO coping is not directly covered by Technical Specification (TS) requirements; however, SBO coping equipment are covered by various Technical Specification requirements which are consistent with the coping analysis assumptions when the units are in MODES 1-6. Consequently, a non-SBO Unit's EDG credited for SBO coping in the SBO Unit may not be available; however, an assessment of risk is performed for these outages which include the impact on SBO coping for the non-outage unit.

REFERENCES

1. Regulatory Guide 1.155, Station Blackout (August 1988)

2. TXX-92447, dated October 1, 1992

3. NUMARC 87-00, Guideline and Technical Basis for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors, Revision 1, August 1991

4. TXX-96405, dated July 10, 1996

5. TXX-96475, dated October 1, 1996