TABLE OF CONTENTS

CHAPTER 5 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF TABLES

LIST OF FIGURES

LIST OF FIGURES

LIST OF FIGURES

LIST OF FIGURES

CHAPTER 5 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 SUMMARY DESCRIPTION

The reactor coolant system includes those systems and components which contain or transport fluids coming from, or going to the reactor core. These systems form a major portion of the reactor coolant pressure boundary. This chapter of the Final Safety Analysis Report provides information regarding the reactor coolant system and pressure-containing appendages out to and including isolation valving. This grouping of components is defined as the reactor coolant pressure boundary (RCPB) as follows:

Reactor coolant pressure boundary (RCPB) includes all pressure containing components such as pressure vessels, piping, pumps, and valves, which are:

a. Part of the reactor coolant system, or

b. Connected to the reactor coolant system, up to and including any and all of the following:

   1. The outermost containment isolation valve in piping which penetrates primary reactor containment

   2. The second of the two valves normally closed during normal reactor operation in system piping which does not penetrate primary reactor containment

   3. The reactor coolant system safety/relief valve piping

This chapter also deals with various subsystems to the RCPB which are closely allied to it. Specifically, Section 5.4 deals with these subsystems.

The nuclear system pressure relief system protects the reactor coolant pressure boundary from damage due to overpressure. To protect against overpressure, pressure-operated relief valves are provided that can discharge steam from the nuclear system to the suppression pool. The pressure relief system also acts automatically to depressurize the nuclear system in the event of a loss-of-coolant accident in which the high pressure core spray (HPCS) system fails to maintain reactor vessel water level.

Depressurization of the nuclear system allows the low pressure core cooling systems to supply enough cooling water to adequately cool the fuel.

Detection of Leakage Through Reactor Coolant Pressure Boundary, in subsection 5.2.5, establishes the limits on nuclear system leakage inside the drywell so that appropriate action can be taken before the integrity of the nuclear system process barrier is impaired.

The reactor vessel and appurtenances are described in Section 5.3, Reactor Vessel. The major safety consideration for the reactor vessel is concerned with the ability of the vessel to function as a radioactive material barrier. Various combinations of loading are considered in the vessel design. The vessel meets the requirements of various applicable codes and criteria. The possibility of brittle fracture is considered, and suitable design, material selection, material surveillance activity, and operational limits are established that avoid conditions where brittle fracture is possible.

The reactor recirculation system provides coolant flow through the core. Adjustment of the core coolant flow rate changes reactor power output, thus providing a means of following plant load demand without adjusting control rods. The recirculation system is designed to provide a slow coastdown of flow so that fuel thermal limits cannot be exceeded as a result of recirculation system malfunctions. The arrangement of the recirculation system routing is such that a piping failure cannot compromise the integrity of the floodable inner volume of the reactor vessel.

Venturi type main steam line flow restrictors are installed in each main steam line inside the primary containment. The restrictors are designed to limit the loss of coolant resulting from a main steam line break outside the primary containment. The coolant loss is limited so that reactor vessel water level remains above the top of the core during the time required for the main steam line isolation valves to close. This action protects the fuel barrier.

Two fast operating isolation valves are installed on each main steam line; one is located inside, and the other is located outside the primary containment. In the event that a main steam line break occurs inside the containment, closure of the isolation valve outside the primary containment acts to seal the primary containment itself. The main steam line isolation valves automatically isolate the reactor coolant pressure boundary in the event a pipe break occurs downstream of the isolation valves. This action limits the loss of coolant and the release of radioactive materials from the nuclear system.

The reactor core isolation cooling (RCIC) system provides makeup water to the core during a reactor shutdown in which feedwater flow is not available. The system is started automatically upon receipt of a low reactor water level signal or manually by the operator. Water is pumped to the core by a turbine-pump driven by reactor steam.

The residual heat removal (RHR) system includes a number of pumps and heat exchangers that can be used to cool the nuclear system under a variety of situations. During normal shutdown and reactor servicing, the RHR system removes residual and decay heat. The RHR system allows decay heat to be removed whenever the main heat sink (main condenser) is not available (e.g., hot standby). One mode of RHR operation allows the removal of heat from the primary containment following a loss-of-coolant accident. Another operational mode of the RHR system is low pressure coolant injection (LPCI). LPCI operation is an engineered safeguard for use during a postulated loss-of-coolant accident. This operation is described in Section 6.3, Emergency Core Cooling Systems. The low pressure core spray system (LPCS) also provides protection to the nuclear system.

The reactor water cleanup system recirculates a portion of reactor coolant through a filter-demineralizer to remove particulate and dissolved impurities from the reactor coolant. It also removes excess coolant from the reactor system under controlled conditions.

Design and performance characteristics of the reactor coolant system and its various components will be found in Table 5.4-1.

5.1.1 Schematic Flow Diagram

Schematic flow diagrams of the reactor coolant system denoting all major components, principal pressures, temperatures, enthalpies, flow rates, and coolant volumes for normal steady-state operating conditions at rated power are presented in Figures 5.1-1 and 5.1-2.

5.1.2 Piping and Instrumentation Diagram

Piping and instrumentation diagrams covering the systems included within the reactor coolant system and connected systems are presented in the following:

a. The nuclear boiler shown in Figures 5.2-6, 5.2-7, and 5.2-8

b. Main steam shown in Figure 5.2-6

c. Feedwater shown in Figure 5.2-6

d. Recirculation system shown in Figures 5.4-2 and 5.4-3

e. Reactor core isolation cooling system shown in Figures 5.4-10 and 5.4-11

f. Residual heat removal system shown in Figures 5.4-16 and 5.4-17

g. Reactor water cleanup system shown in Figures 5.4-21, 5.4-25, and 5.4-26

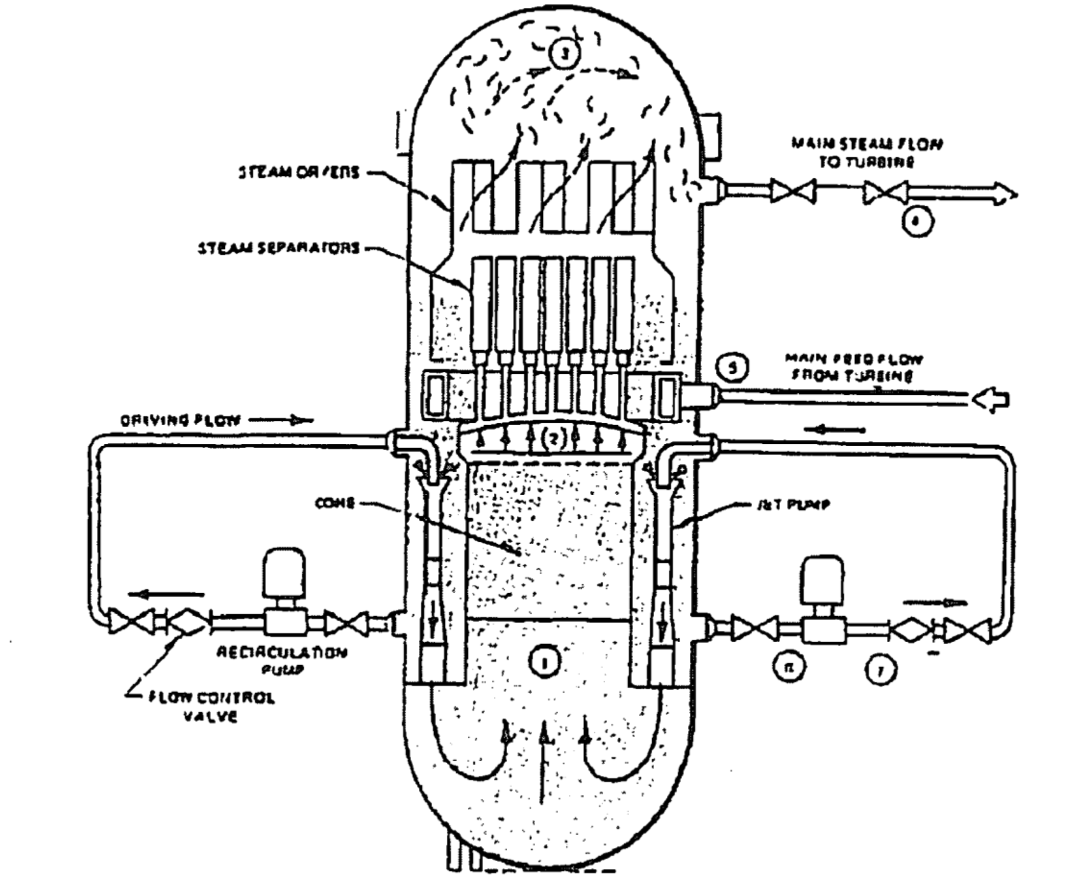
h. High pressure core spray system shown in Figure 6.3-1

i. Low pressure core spray system shown in Figure 6.3-4

5.1.3 Elevation Drawing

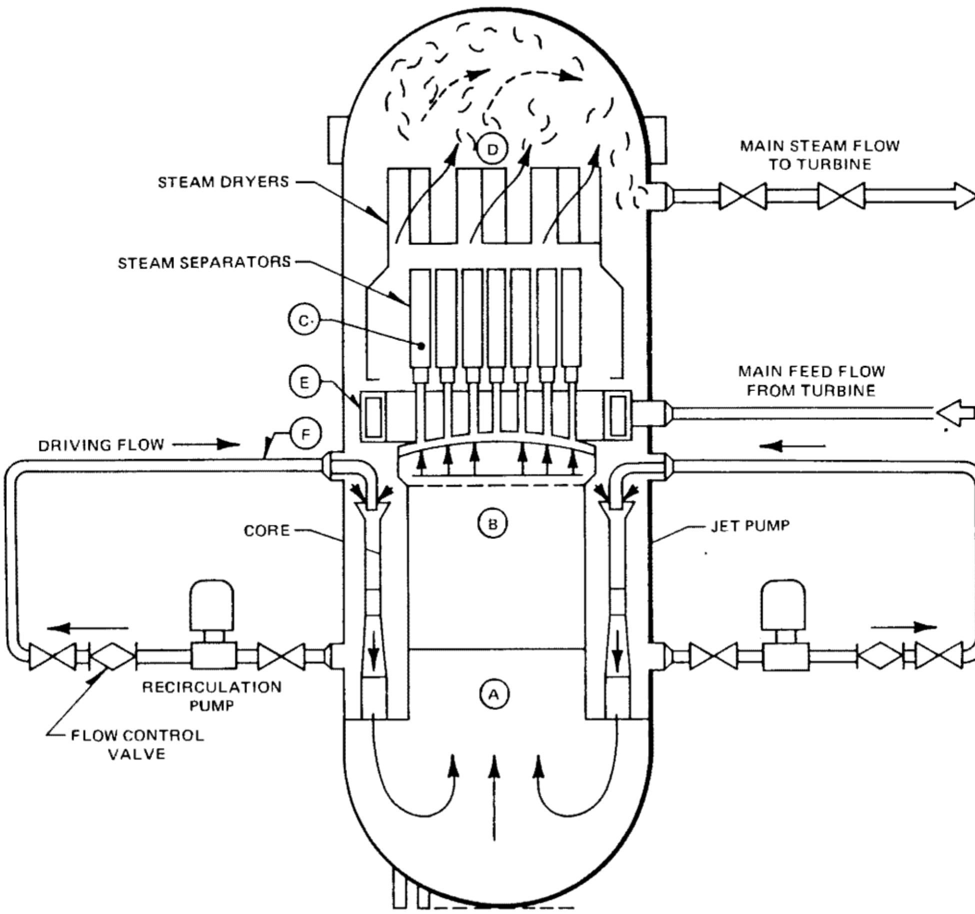
An elevation drawing showing the principal dimensions of the reactor and coolant system in relation to the containment is shown in Figures 5.1-3 and 5.1-4.

	Pressure (psia)	Flow (lb/h)	Temperature (°F)	Enthalpy (Btu/lb)
1. Core Inlet	1074	112.5×10^6	531	525.1
2. Core Outlet	1047	112.5×10^6	550	644
3. Separator Outlet (Steam Dome)	1040	18.97×10^6	549	1190.8
4. Steam Line (2[nd] Isolation Valve)	985	18.97×10^6	543	1190.8
5. Feedwater Inlet	1065	19.11×10^6	420.1	397.8
6. Recirc Pump Suction	1043	33.6×10^6	531	524.6
7. Recirc Pump Discharge	1292	33.6×10^6	532	526.1

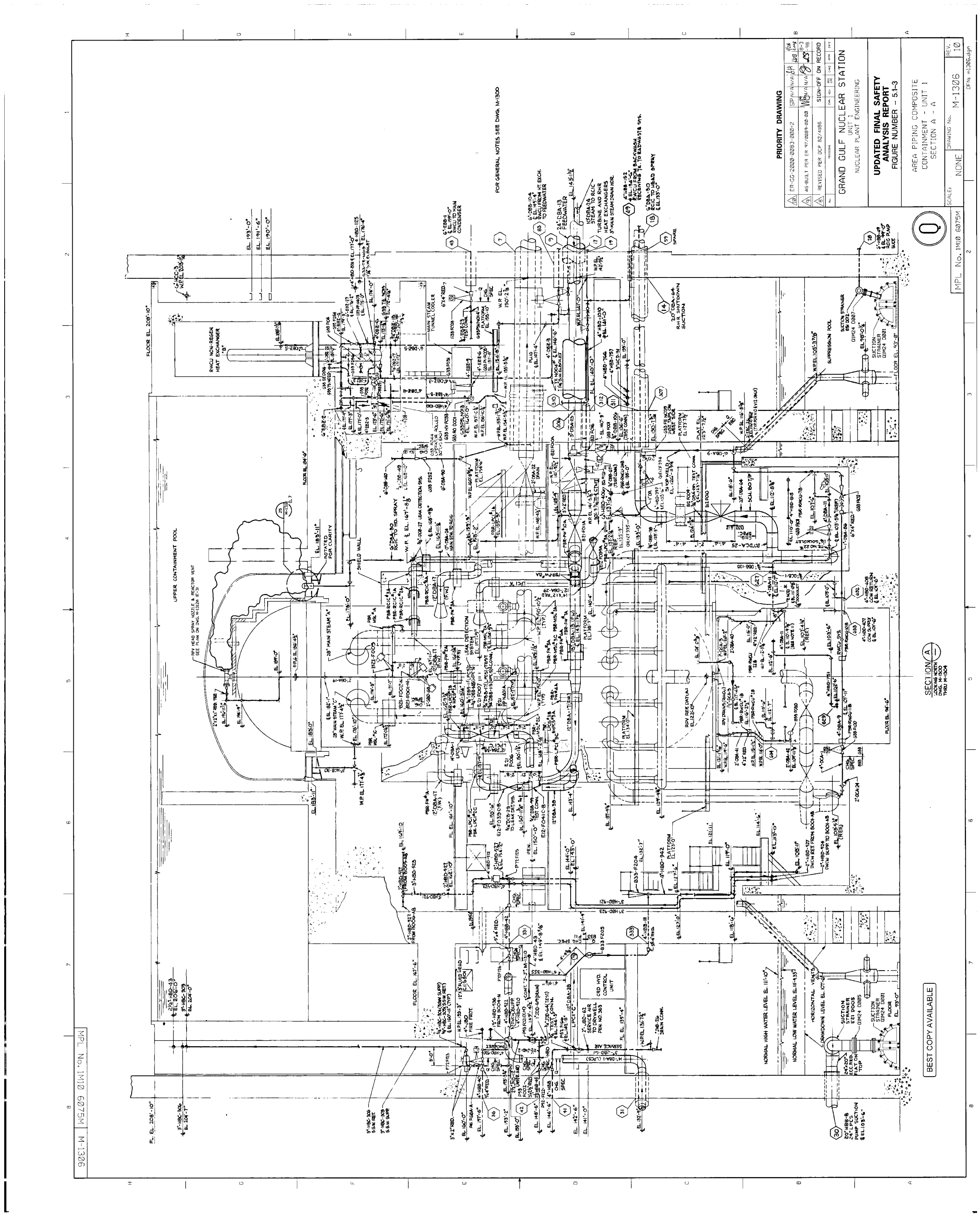


GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	RATED OPERATING CONDITIONS OF THE BOILING WATER REACTOR FIGURE 5.1-1

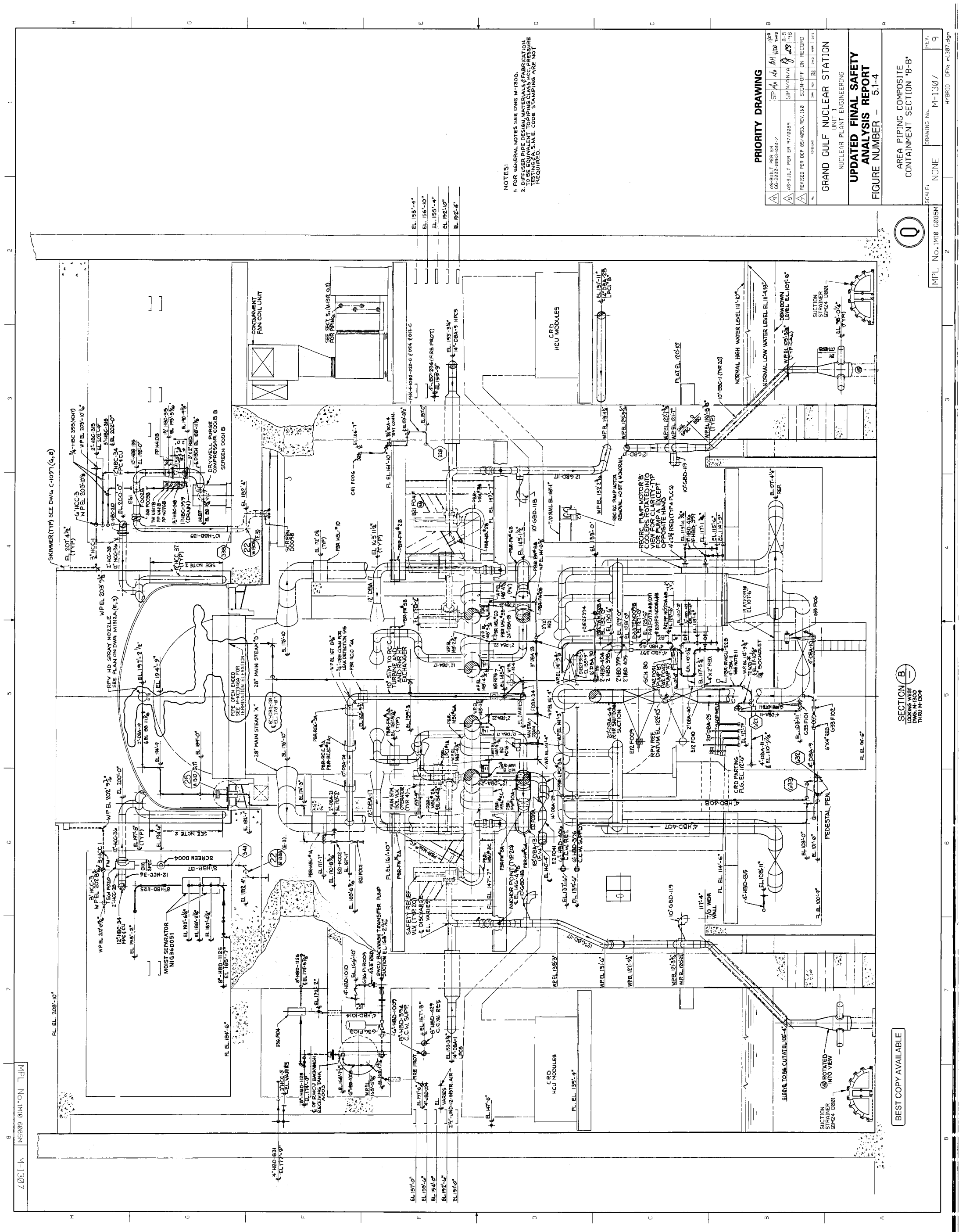
	VOLUME OF FLUID (ft^3)
A LOWER PLENUM	3700
B CORE	2065
C UPPER PLENUM AND SEPARATORS	2300
D DOME (ABOVE NORMAL WATER LEVEL)	7340
E DOWNCOMER REGION	5320
F RECIRCULATION LOOPS AND JET PUMPS	1020



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	COOLANT VOLUMES OF THE BOILING WATER REACTOR FIGURE 5.1-2



PRIORITY DRAWING
GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER - 5.1-3
AREA PIPING COMPOSITE
CONTAINMENT - UNIT 1
SECTION A - A
M-1306
SECTION A
BEST COPY AVAILABLE


PRIORITY DRAWING
AS-BUILT PER ER GG-2000-0083-000-2
AS-BUILT PER ER 97/0089
REVISED PER DCP 85/4053, REV. 1&0
SIGN-OFF ON RECORD
GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER – 5.1-4
AREA PIPING COMPOSITE CONTAINMENT SECTION 'B-B'
SCALE: NONE
DRAWING No. M-1307
REV. 9
HYBRID DFN: m1307.dgn
MPL No. 1M10 6085M
BEST COPY AVAILABLE
SECTION B

5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY

This section discusses measures employed to provide and maintain the integrity of the reactor coolant pressure boundary (RCPB) for the plant design lifetime.

5.2.1 Compliance with Codes and Code Cases

5.2.1.1 Compliance with 10 CFR Part 50, Section 50.55a

Table 3.2-1 which shows compliance with the rules of 10 CFR 50, Codes and Standards, is included in Section 3.2. Code edition, applicable addenda, and component dates are in accordance with 10 CFR 50.55a.

5.2.1.2 Applicable Code Cases

The reactor pressure vessel and appurtenances, and the RCPB piping, pumps, and valves, have been designed, fabricated, and tested in accordance with the applicable edition of the ASME Code, including addenda that were mandatory at the order date for the applicable components. Section 50.55a of 10 CFR 50 requires code case approval only for Class 1 components. These code cases contain requirements or special rules which may be used for the construction of pressure-retaining components of Quality Group A. The various ASME Code Case interpretations that were applied to components in the RCPB are listed in Table 5.2-1.

5.2.2 Overpressure Protection

The vessel overpressure protection system is designed to satisfy the requirements of Section III, Nuclear Power Plant Components, of the ASME Boiler and Pressure Vessel Code. The general requirements for protection against overpressure, as given in Article NB-7000 of Section III of the Code, recognize that reactor vessel overpressure protection is one function of the reactor protective systems, and allow the integration of pressure relief devices with the protective systems of the nuclear reactor. Therefore, the scram protective system is considered a complementary pressure protection device.

This section provides evaluation of the systems that protect the RCPB from overpressurization including:

a. The reactor coolant system

b. Emergency systems connected to the reactor coolant system

c. Any blowdown or heat dissipation systems connected to the discharge of these pressure-relieving devices

[HISTORICAL INFORMATION] [The baseline analyses were performed based on the initial core, which was a GE 8x8 fueled core. These analyses included the determination of pressure relief capacity, the design of the low-low set relief logic, the identification of the limiting event, and demonstration of the adequacy of the overpressure protection system design. Analyses supporting operation in the Maximum Extended Operating Domain (MEOD) for the initial core are described in Appendix 15D and show that adequate pressure protection is available during operation in the MEOD.]

Analyses performed for reload cores for the limiting overpressurization event and analyses for the ATWS evaluation performed for EPU (described in Section 15.8) confirmed that there is sufficient pressure relief capacity.

5.2.2.1 Design Basis

Overpressure protection is provided in complete conformance with 10 CFR 50, Appendix A, General Design Criterion 15. Preoperational and startup instructions are given in Chapter 14.

5.2.2.1.1 Safety Design Bases

The nuclear pressure-relief system has been designed:

a. To prevent overpressurization of the nuclear system that could lead to the failure of the reactor coolant pressure boundary

b. To provide automatic depressurization for small breaks in the nuclear system occurring with maloperation of the high pressure core spray (HPCS) system so that the low pressure coolant injection (LPCI) and the low pressure core spray (LPCS) systems can operate to protect the fuel barrier

c. To permit verification of its operability

d. To withstand adverse combinations of loadings and forces resulting from operation during abnormal, accident, or special event conditions

The safety/relief valve capacity of this plant is sized to limit the primary system pressure, including transients, to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components. The essential ASME requirements, which are all met by this analysis, are:

a. The protection of vessels in a nuclear power plant is dependent upon many protective systems to relieve or terminate pressure transients. Installation of pressure relieving devices may not independently provide complete protection.

b. The safety/relief valve sizing evaluation assumed credit for operation of the scram protective system, which may be tripped by any one of two sources: i.e., a direct flux signal. The direct scram signal is derived from position switches mounted on the main steam line isolation, or from pressure transmitters sensing turbine trip fluid pressure, or from pressure transmitters sensing turbine control fluid pressure (see subsection 7.2.1.1.4).

   The position switches are actuated when the respective valves are closing and following 10-percent travel of full stroke. A low-trip fluid pressure is indicative of turbine stop valve closure and causes trip units to actuate. A low-control fluid pressure is indicative of turbine control valve fast closure and causes other trip units to actuate.

   Credit is also taken for the dual purpose safety/relief valves in their ASME Code qualified modes of safety operation. That is, whenever system pressure increases to the relief pressure set point of a group of valves having the same set point, half of those valves are assumed to operate in the relief mode, opened by pneumatic power actuation. When the system pressure increases to the valve spring set pressure of a group of valves, those valves not already considered open are assumed to begin opening and to reach full-open at 103 percent of the valve spring set pressure.

c. The nominal pressure setting of at least one safety/relief valve connected to any vessel or system shall not be greater than a pressure at the safety/relief valves corresponding to the design pressure (1250 psig) of the protected vessel.

d. The rated capacity of the pressure relieving devices shall be sufficient to prevent a rise in pressure within the protected vessel of more than 110 percent of the design pressure (1.10 x 1250 psig = 1375 psig) for events defined in subsection 4.3.1.

e. Full account is taken of the pressure drop on both the inlet and discharge sides of the valves. All safety/relief valves discharge into the suppression pool through a discharge pipe from each valve. The pipes are designed to achieve sonic flow conditions through the valve, thus providing flow independence to discharge piping losses.

5.2.2.1.2 Power Generation Design Bases

The nuclear pressure-relief system safety/relief valves have been designed to meet the following power generation bases:

a. Discharge to the containment suppression pool

b. Correctly reclose following operation so that maximum operational continuity can be obtained

5.2.2.1.3 Discussion

The ASME Boiler and Pressure Vessel Code requires that each vessel designed to meet Section III be protected from overpressure under upset conditions. The code allows a peak allowable pressure of 110 percent of vessel design pressure under upset conditions. The code specifications for safety valves require that: (1) the lowest safety valve be set at or below vessel design pressure and (2) the highest safety valve be set so that total accumulated pressure does not exceed 110 percent of the design pressure for upset conditions. The safety/relief valves are designed to open via either of two modes of operation, automatically using a pneumatic power actuator or by self-actuation in the spring lift mode. Opening set points are different for each of these two modes for operating the valves and are listed in Table 5.2-2. These set points satisfy the ASME Code specifications for safety valves, because all valves open at less than the nuclear system design pressure of 1250 psig.

The automatic depressurization capability of the nuclear system pressure relief system is evaluated in Section 6.3, Emergency Core Cooling Systems, and in Section 7.3, Engineered Safety Feature Systems.

The following detailed criteria are used in the selection of relief valves:

a. Must meet requirements of ASME Code, Section III

b. Must qualify for 100 percent of nameplate capacity credit for the overpressure protection function

c. Must meet other performance requirements such as response time, etc., as necessary to provide relief functions

The safety/relief valve discharge piping is designed, installed, and tested in accordance with the ASME Code, Section III from the valve to the first anchor.

5.2.2.1.4 Safety Valve Capacity

The safety valve capacity of this plant is adequate to limit the primary system pressure, including transients, to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels (up to and including Winter 1971 Addenda. These requirements are summarized in Section 5.2.2.1.1.

Table 5.2-7 lists the systems which initiate during the design basis overpressure event.

5.2.2.2 Design Evaluation

5.2.2.2.1 Method of Analysis

[HISTORICAL INFORMATION] [To design the pressure protection for the nuclear boiler system, extensive analytical models representing all essential dynamic characteristics of the system are simulated on a large computing facility. These models include the hydrodynamics of the flow loop, the reactor kinetics, the thermal characteristics of the fuel and its transfer of heat to the coolant, and all the principal controller features, such as feedwater flow, recirculation flow, reactor water level, pressure, and load demand. These are represented with all their principal nonlinear features in models that have evolved through extensive experience and favorable comparison of analysis with actual BWR test data.

A detailed description of the model used in the initial core analysis is documented in Reference 6. Included within this model are components of the reactor vessel pressure protection system. Dual safety/relief valves are simulated in a nonlinear representation, and the model thereby allows full investigation of the various valve response times, valve capacities, and actuation set points that are available in applicable hardware systems.

Typical valve characteristics, as modeled, are presented in Figures 5.2-2 and 5.2-3 for the power-actuated relief and spring-action safety modes of the dual-purpose safety/relief valves. The associated bypass, turbine control valve, main steam isolation valve characteristics, and pump trip due to high reactor pressure are also represented fully in the model. The input parameters and initial conditions used in this analysis are the same as those provided in Table 15.0-3.]

5.2.2.2.2 System Design

[HISTORICAL INFORMATION] [A parametric study was conducted to determine the required steam flow capacity of the safety/relief valves based on the following assumptions.

5.2.2.2.2.1 Operating Conditions

a. Operating power = 3993 MWt (104.2 percent of original nuclear boiler rated power)

b. Vessel dome pressure ≤1045 psig (Technical Specification Limit)

c. Steam flow = 17.312×10^6 lb/hr (105 percent of nuclear boiler rated steam flow)

These conditions are the most severe because maximum stored energy exists at these conditions. At lower power conditions the transients would be less severe.

Evaluations of the sensitivity of the performance of the system to variations in system and equipment conditions, parameters, and performance were conducted in order to determine the limiting conditions for overpressure protection. The reference which contains these limiting conditions is the Reactor Overpressure Protection Report for Grand Gulf developed by General Electric, General Electric document number 22A5400.]

5.2.2.2.2.2 Transients

The overpressure protection system accommodates the most severe pressurization transient. There are two major transients, the closure of all main steam line isolation valves and a turbine/generator trip (with a coincident closure of the turbine steam bypass system valves) that represent the most severe abnormal operation transients resulting in a nuclear system pressure rise. [HISTORICAL INFORMATION] [The evaluation of transient behavior with final plant configuration for the initial core showed that the isolation valve closure is slightly more severe when credit was taken only for indirect derived scrams, i.e., flux scram; therefore, it was used as the overpressure protection basis event (Reference 1). The required safety/relief valve capacity was determined by analyzing the main steam isolation valve (MSIV) closure with indirect scram transient, as described in subsection 5.2.2.2.3.1.]

These two potentially limiting overpressurization events were analyzed for EPU and described in the PUSAR Section 2.8.4.2. However, based on both plant initial core analyses and subsequent power uprate evaluations, the main steam isolation valve closure with scram on high flux is more limiting with respect to reactor overpressure. The EPU analysis is demonstrated that: (1) pressurization events and overpressure protection features adequately account for the effects of EPU; and (2) the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded. Furthermore, the adequacy of the pressure relief system is also demonstrated by the overpressure protection evaluation performed for each core reload and by the ATWS evaluation as described in Section 2.8.5.7 of the PUSAR.

5.2.2.2.2.3 Deleted

5.2.2.2.2.4 Safety/Relief Valve Initial Core Analysis Specification

a. Valve groups:

Power-actuated relief mode - 4 groups
Spring-action safety mode - 3 groups

b. Pressure set point (maximum safety limit):

Power-actuated relief mode - 1125-1155 psig
Spring-action safety mode - 1175-1215 psig

The set points are assumed at a conservatively high level above the nominal set points. This is to account for initial set point errors and any instrument set point drift that might occur during operation. Typically the assumed set points in the analysis are 4 percent above the actual nominal set points. High conservative safety/relief valve response characteristics are also assumed.

Improper safety/relief valve set points as a result of erroneous set point calculations are very unlikely due to internal GEH procedures which are implemented in accordance with the requirements of 10 CFR 50 Appendix B, Criterion III. These design verification procedures require that the set points established through the normal design and analysis practices be verified by independent calculations. Each valve is individually tested for proper set point, as discussed in Subsection 5.2.2.10. Technical Specifications require that verification of set points be maintained throughout the life of the plant.

In addition, the valve set points for the safety and relief modes are set independently from each other. Consequently, a common mode failure of the relief valve set points would not affect the safety valve set points and vice versa.

5.2.2.2.2.5 Safety Valve Capacity

Sizing of the safety valve capacity is based on establishing an adequate margin from the peak vessel pressure to the vessel code limit (1375 psig) in response to the reference transients.

5.2.2.2.3 Evaluation of Results

5.2.2.2.3.1 Safety/Relief Valve Capacity

The required safety/relief valve capacity is determined by analyzing the pressure rise from an MSIV closure with flux scram transient. The plant is assumed to be operating at the turbine generator design conditions at a maximum vessel dome pressure of 1045 psig. The analysis hypothetically assumes the failure of the direct isolation valve position scram. The reactor is shut down by the backup, indirect, high neutron flux scram. For the analysis, the power-actuated relief set points of the safety/relief valve are assumed to be 1153 psig, and the spring-action safety set points to be in the range of 1227 to 1238 psig. The analysis indicates that the design valve capacity is capable of maintaining adequate margin below the peak ASME Code allowable pressure in the nuclear system (1375 psig).

The calculations to support relief valve discharge coefficients and capacities are provided in Table 5.2-2a.

Figure 5.2-4 shows curves produced by this analysis. The sequence of events in Table 5.2-10 assumed in this analysis was investigated to meet code requirements and to evaluate the pressure relief system exclusively.

Under the General Requirements for Protection Against Overpressure as given in Section III of the ASME Boiler and Pressure Vessel Code, credit can be allowed for a scram from the reactor protection system. In addition, credit is also taken for the protective circuits which are indirectly derived when determining the required safety/relief valve capacity. The back-up reactor high neutron flux scram is conservatively applied as a design basis in determining the required capacity of the pressure relieving dual purpose safety/relief valves. Application of the direct position scrams in the design basis could be used since they qualify as acceptable pressure protection devices when determining the required safety/relief valve capacity of nuclear vessels under the provisions of the ASME Code. The safety/relief valves are operated in a relief mode (pneumatically) at set points lower than those specified for the safety function. This ensures sufficient margin between anticipated relief mode closing pressures and valve spring forces for proper seating of the valves.

The parametric relationship between peak vessel (bottom) pressure and safety/relief valve capacity for the MSIV transient with high flux scram is described in Figure 5.2-4. Also shown in Figure 5.2-4 is the parametric relationship between peak vessel (bottom) pressure and safety/relief valve capacity for the generator load rejection with a coincident closure of the turbine bypass valves and direct scram, which is the most severe transient when direct scram is considered. The parametric relationships were established using the point -kinetics - based REDY computer code (Reference 1). Pressures shown for flux scram will result only with multiple failure in the redundant direct scram system.

The time response of the vessel pressure to the MSIV transient with flux scram and the generator load rejection with a coincident closure of the turbine bypass valves and direct scram for 20 valves is illustrated in Figure 5.2-5. This shows that the pressure at the vessel bottom exceeds 1250 psig for less than 5 seconds, which is not long enough to transfer any appreciable amount of heat into the vessel metal which was at a temperature well below 550 F at the start of the transient.

5.2.2.2.3.2 Pressure Drop in Inlet and Discharge

Pressure drop in the piping from the reactor vessel to the valves is taken into account in calculating the maximum vessel pressures. Pressure drop in the discharge piping to the suppression pool is limited by proper discharge line sizing to prevent backpressure on each safety/relief valve from exceeding 40 percent of the valve inlet pressure, thus assuring choked flow in the valve orifice and no reduction of valve capacity due to the discharge piping. Each safety/relief valve has its own separate discharge line.

5.2.2.2.3.3 Low-Low Set Relief Function

In order to ensure that no more than one relief valve reopens following a reactor isolation event, two valves are provided with lower opening and closing set points and four valves are provided with lower closing set points only (see Table 5.2-2). These set points override the normal set points following the initial opening of any of the relief valves and act to hold open these valves longer, thus preventing subsequent reopening of more than one valve. This system logic is referred to as the low-low set relief logic and functions to ensure that the containment design basis of one safety/relief valve operating on subsequent actuations is met.

The low-low set relief function is armed whenever any safety/relief valve is called upon to open in the normal relief mode by pressure sensors. Thus, the low-low set valves will not actuate during normal plant operation, even though the reopening set point of one of the valves is in the normal operating pressure range. This arming method results in the low-low set SRVs opening initially during an overpressure transient only if one or more SRVs open at the normal relief opening set point.

The lowest set point low-low set valve will cycle to remove decay heat. Since this valve will have a larger differential between its opening and closing set pressures than assumed for the normal relief function, the number of single safety/relief valve actuations during isolation events will be reduced. Table 5.2-2 shows the opening and closing set points for the low-low set safety/relief valves.

The assumptions used in the calculation of the pressure transient after the initial opening of the relief valves are:

1. The transient event is a 3-second closure of all MSIVs with position scram

2. Nominal relief valve set points are used

3. The maximum expected relief capacity is used

4. Relief valve opening response times (Figure 5.2-12) are used

5. The closing set point of the relief valves is 100 psi below the opening set point

6. ANS plus 20 percent decay heat at infinite exposure is used

The results using the above assumptions are shown in the reactor vessel pressure transient curve (Figure 5.2-12a). Despite the conservative input assumptions which tend to maximize the pressure peaks on subsequent actuations, there is a 76 psi margin for avoiding the second pop of more than one valve. The system is single-failure proof, since a failure of one of the low-low set valves still gives a 58 psi margin for avoiding multiple valve actuations.

5.2.2.3 Piping and Instrument Diagrams

Figures 5.2-8 through 5.2-11 show the schematic location of pressure-relieving devices for:

a. The reactor coolant system

b. The primary side of the auxiliary or emergency systems interconnected with the primary system

c. Any blowdown or heat dissipation system connected to the discharge side of the pressure relieving devices

5.2.2.4 Equipment and Component Description

5.2.2.4.1 Description

The nuclear pressure-relief system consists of safety/relief valves located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. These valves protect against overpressure of the nuclear system.

The safety/relief valves provide three main protection functions:

a. Overpressure relief operation. The valves open automatically to limit a pressure rise.

b. Overpressure safety operation. The valves function as safety valves and open (self-actuated operation if not already automatically opened for relief operation) to prevent nuclear system overpressurization.

c. Depressurization operation. The ADS valves open automatically as part of the emergency core cooling system (ECCS) for events involving small breaks in the nuclear system process barrier. The location and number of the ADS valves can be determined from Figure 5.2-8.

Chapter 15 discusses the events which are expected to activate the primary system safety/relief valves. The chapter also summarizes the number of valves expected to operate during the initial blowdown of the valves and the expected duration of this first blowdown. For several of the events it is expected that the lowest set safety/relief valve will reopen and reclose as generated heat drops into the decay heat characteristics. The pressure increase and relief cycle will continue with lower frequency and shorter relief discharges as the decay heat drops off and until such time as the RHR system can dissipate this heat. The duration of each relief discharge should in most cases be less than 30 seconds. Remote manual actuation of the valves from the control room is recommended to minimize the total number of these discharges, with the intent of achieving extended valve seat life.

The valves were manufactured by Dikkers Valve Company to ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, 1974 Edition with Addenda to and including Summer 1976. They comply with ASME III, Paragraph NB-7640 as safety valves with auxiliary actuating devices.

The safety/relief valves are balanced-type, spring-loaded safety valves provided with an auxiliary power actuated device which allows opening of the valve even when pressure is less than the safety-set pressure of the valve. Previous undesirable performance on operating BWRs was associated principally with multiple stage pilot operated safety/relief valves. These newer power-operated safety valves employ significantly fewer moving parts wetted by the steam, and are therefore considered an improvement over the previously used valves.

Quantities, set points and associated capacities are shown in Table 5.2-2.

A schematic of the main safety/relief valve is shown in Figure 5.2-13. It is opened by either of two modes of operation:

a. The spring mode of operation which consists of direct action of the steam pressure against a spring-loaded disk that will pop open when the valve inlet pressure force exceeds the spring force. Figure 5.2-4 diagrams the valve lift versus pressure characteristic.

b. The power actuated mode of operation which consists of using an auxiliary actuating device consisting of a pneumatic piston/cylinder and mechanical linkage assembly which opens the valve by overcoming the spring force, even with valve inlet pressure equal to zero psig.

The pneumatic operator is so arranged that if it malfunctions it will not prevent the valve disk from lifting if steam inlet pressure reaches the spring lift set pressure.

For overpressure safety/relief valve operation (self-actuated or spring lift mode), the spring load establishes the safety valve opening set point pressure and is set to open at set points designated in Table 5.2-2. The ASME Code requires that full lift of this mode of operation should be attained at a pressure no greater than 3 percent above the set point.

Attached to the safety/relief valve there is a vent line separate from the discharge line. An orifice is provided on the SRV at the vent line connection to control the pressure above the safety/ relief valve disc. This orifice controls the reclosure pressure of the safety/relief valve based on the anticipated backpressure which results in the vent line when the valve is open and discharging steam.

The safety function of the safety/relief valve is a backup to the relief function described below. The spring-loaded valves are designed and constructed in accordance with ASME Code, Section III, NB 7640 as safety valves with auxiliary actuating devices.

For overpressure relief valve operation (power-actuated mode), each valve is provided with a pressure sensing device which operates at the set points designated in Table 5.2-2. When the set pressure is reached, it operates a solenoid air valve which in turn actuates the pneumatic piston/cylinder and linkage assembly to open the valve.

When the piston is actuated, the delay time, maximum elapsed time between receiving the overpressure signal at the valve actuator and the actual start of valve motion, will not exceed 0.1 seconds. The maximum full stroke opening time will not exceed 0.15 seconds.

The safety/relief valves can be operated in the power-actuated mode by remote-manual controls from the main control room.

Actuation of either solenoid A or solenoid B on the safety/ relief valve will cause the safety/relief valve to open; hence, there is no single failure of a logic component or safety/ relief valve solenoid valve which would result in failure of the main valve to open. The trip units (see Figures 5.2-6 through 5.2-8) for each safety/relief valve within each division are in series, and failure of one of the transmitters will not cause the safety/

relief valves to open. Each safety/relief valve is provided with its own pneumatic accumulator and inlet check valve. The accumulators, interconnecting piping, and associated valving are designed to the requirements of ASME Section III, Class 3, and are seismic Category I. This pneumatic supply system arrangement is shown in Figure 5.2-8. The accumulator capacity is sufficient to provide one safety/relief valve actuation, which is all that is required for overpressure protection. Subsequent actuations for an overpressure event can be spring actuations to limit reactor pressure to acceptable levels.

The safety/relief valves are designed to operate to the extent required for overpressure protection in the following accident environments:

a. 340 F for 3 hours at drywell design pressure

b. 320 F for an additional 3-hour period, at drywell design pressure

c. 250 F for an additional 18-hour period, at 25 psig

d. 200 F during the next 99 days at 20 psig. The duration of operability is 2 days, following which the valves will remain fully open or closed for the remaining time period.

The automatic depressurization system (ADS) utilizes selected safety/relief valves for depressurization of the reactor (see Section 6.3, Emergency Core Cooling System). Each of the safety/relief valves utilized for automatic depressurization is equipped with two air accumulators and associated inlet check valves. The ADS valve air accumulators are recharged by two of four large air receivers. Two air receivers supply the accumulators associated with the ADS valves on steam lines “A” and “C.” Two additional air receivers supply the accumulators for the ADS valves on steam lines “B” and “D.” The air receivers, air accumulators, interconnecting piping, and associated valves are designed to the requirements of ASME Section III, Class 3, and are seismic Category I. The pneumatic supply system arrangement is shown in Figure 5.2-8. The receivers and accumulators ensure that the valves can be held open following failure of the air supply to the receivers. The pneumatic supply system is sized to be capable of opening the valves against 70 percent of the drywell design pressure [16.6 psig (31.3 psia)]. The accumulator's capacity is sufficient for each ADS valve to provide two actuations against 70 percent of the drywell design pressure. Alternatively, the receiver's capacity is sufficient for 100 actuations, over a six-hour period, of the low-low set point safety/relief valve. One additional design requirement of the ADS system is that the ADS valves must be capable of remaining open for 100 days following a LOCA.

The ADS pneumatic system has been analyzed considering DBA temperature and pressure profiles along with the maximum design leakage of the MSRV actuators and the maximum allowable leakage of the pneumatic system. For the worst case of five valves (four ADS and one low-low set valve) on one division, the pneumatic system is capable under post-accident conditions of providing two actuations for each ADS valve and then holding the ADS valves open for at least 3.5 days. For longer periods of time, the receivers/ accumulators can be recharged by utilizing compressed air cylinders and the test connection provided outside the containment on the instrument air supply penetration piping, should the nonsafety-related instrument air system be unavailable. The instrument air supply line from the outside containment isolation valve to the air receiver tanks is designed to the requirements of ASME Section III, Class 2 and 3, as applicable, and is seismic Category I. If the air supply line for a non-ADS safety/relief valve air accumulator were to break upstream of the ball check valve, a higher than normal flow condition would exist and a high flow alarm in the control room would alert the operator. On receipt of the high flow alarm, an operator is dispatched to determine if a leak exists.

Each safety/relief valve discharges steam through a discharge line to a point below the minimum water level in the suppression pool. Safety/relief valve discharge line piping from the safety/relief valve to the suppression pool consists of two parts. The first is attached at one end to the safety/relief valve and at its other end to the structural steel just below the main steam header through a pipe anchor. The main steam piping, including this portion of the safety/relief valve discharge piping, is analyzed as a complete system. This portion of the safety/relief valve discharge lines is therefore classified as Quality Group C and seismic Category I.

The second part of the safety/relief valve discharge piping extends from the upstream anchor to the suppression pool. Because of the upstream anchor on this part of the line, it is physically decoupled from the main steam header and is therefore analyzed as a separate piping system. For the non-ADS valves, the discharge piping from the upstream anchor to the drywell wall is Quality

Group D and the piping extending from the drywell wall to the quencher is Quality Group C. For the ADS valves, the discharge piping from the upstream anchor to the quencher is Quality Group C. In analyzing this part of the discharge piping, the following load combination will be considered as a minimum:

Pressure and temperature
Dead weight
Fluid dynamic loads due to S/R valve operation
Anchor relative seismic (SSE) movement

As a part of the preoperational and startup testing of the main steam lines, movement of the safety/relief valve discharge line will be monitored. The safety/relief valve discharge piping is designed to limit valve outlet pressure to 40 percent of maximum valve inlet pressure with the valve wide open. Water in the line more than a few feet above suppression pool water level would cause excessive pressure at the valve discharge when the valve is again opened. For this reason, two vacuum relief valves are provided on each safety/relief valve discharge line to prevent drawing an excessive amount of water up into the line as a result of steam condensation following termination of relief operation. The safety/relief valves are located on the main steam line piping, rather than on the reactor vessel top head, primarily to simplify the discharge piping to the pool and to avoid the necessity of having to remove sections of this piping when the reactor head is removed for refueling. In addition, valves located on the steam lines are more accessible during a shutdown for valve maintenance.

The nuclear pressure relief system automatically depressurizes systems to operate as a backup for the high pressure core spray (HPCS) system. Further descriptions of the operation of the automatic depressurization feature are found in Section 6.3, Emergency Core Cooling Systems, and in subsection 7.3.1.1.1, Emergency Core Cooling Systems Control.

5.2.2.4.2 Design Parameters

Table 5.2-3 lists design temperature, pressure, and maximum test pressure for the RCPB components. (Refer to Section 3.7 for discussion of the input criteria for design of seismic Category I structures, systems, and components.)

The design requirements established to protect the principal components of the reactor coolant system against environmental effects are discussed in Section 3.11.

5.2.2.4.2.1 Safety/Relief Valve

The discharge area of the valve is 18.4 in.^{2} and the coefficient of discharge K_D is equal to 0.873 ($K = 0.9\ K_D$). The design pressure and temperature of the valve inlet and outlet are 1375 psig at 585 F and 625 psig at 500 F, respectively.

The valves have been designed to achieve the maximum practical number of actuations consistent with state-of-the-art technology. Cycle testing has demonstrated that the valves are capable of at least 60 actuation cycles between required maintenance. Discharge of pipeline debris through the valve will, however, adversely affect seat leakage.

All challenges to the main steam safety/relief valves will be documented and reported in accordance with 10 CFR 50.73 reporting requirements.

See Figure 5.2-13 for a schematic cross section of the valve.

5.2.2.5 Mounting of Pressure Relief Devices

The pressure relief devices are located on the main steam piping header. The mounting consists of a special contour nozzle and connection that accounts for the thrust, bending, and torsional loadings which the main steam pipe and relief valve discharge pipe are subjected to. This includes:

a. The thermal expansion effects of the connecting piping

b. The dynamic effects of the piping due to earthquake

c. The reactions due to transient unbalanced wave forces exerted on the safety/relief valves during the first few seconds after the valve is opened and prior to the time steady-state flow has been established. (With steady-state flow, the dynamic flow reaction forces will be self-equilibrated by the valve discharge piping.)

d. The dynamic effects of the piping and branch connection due to the turbine stop valve closure

In no case will allowable valve flange loads be exceeded nor will the stress at any point in the piping exceed code allowables for any specified combination of loads. The design criteria and analysis methods for considering loads due to SRV discharge are contained in subsection 3.9.3.3.

5.2.2.6 Applicable Codes and Classification

The vessel overpressure protection system is designed to satisfy the requirements of Section III, Nuclear Vessels, of the ASME Boiler and Pressure Vessel Code. The general requirements for protection against overpressure as given in Article 9 of Section III of the Code recognize that reactor vessel overpressure protection is one function of the reactor protective systems and allows the integration of pressure relief devices with the protective systems of the nuclear reactor. Hence, credit is taken for the scram protective system as a complementary pressure protection device. The NRC has also adopted the ASME Codes as part of its requirements in the Code of Federal Regulations (10 CFR 50.55a).

5.2.2.7 Material Specification

Pressure-retaining components of piping and valves in Quality Groups A, B, and C are constructed of the following materials:

Plate	ASME SA-516 Grade 70
Forgings	ASME SA-105 Grade II ASME SA-350 Grade LF1, LF2
Pipe	ASME SA-106 Grade B ASME SA-333 Grade 6
Fittings	ASME SA-234 Grade WPB, WPBW ASME SA-420 Grade WPL-6, WPL-6W ASME SA-105
Castings	ASME SA-216 Grade WCB, WCC ASME SA-352 Grade LCB
Bolting	ASME SA-193 Grade B7, B16 ASME SA-194 Grade 2H, 7 ASME SA-540

Austenitic Stainless Steel

Wrought Austenitic Stainless Steel. Wrought austenitic stainless steel materials shall be limited to Types 304, 304L, 316, 316L.

Cast Austenitic Stainless Steel. Cast austenitic stainless steel materials shall be limited to Grades CF8, CF3, CF3A, and CF8M.

Pressure-retaining components of safety/relief valves are constructed of the following materials:

Component	Form	**Material**	Specification (ASME)	Remarks
Body	Cast	**Carbon Steel**	SA 352 LCB	
Nozzle	Forged	**Carbon Steel**	SA 350 LF2	Seal faced with stainless steel
Disc	Cast	**Stainless Steel**	SA 351 CF3A	

5.2.2.8 Process Instrumentation

Overpressure protection process instrumentation is listed in Table III of Figure 5.2-8.

5.2.2.9 System Reliability

Refer to Appendix 15A.

5.2.2.10 Inspection and Testing

The inspection and testing applicable to safety/relief valves utilizes a quality assurance program which complies with Appendix B of 10 CFR Part 50.

[HISTORICAL INFORMATION] [Prior to initial installation the safety/relief valves were tested at the vendor's shop in accordance with quality control procedures to detect defects and to prove operability prior to installation. The following tests were conducted:

a. Hydrostatic test at specified test conditions.

b. Pneumatic seat leakage test at 90 percent of the nameplate set pressure, with maximum permitted leakage of 30 bubbles per minute emitting from a 0.250 inch diameter hole submerged 1/2 inch below a water surface, or an equivalent test using an approved test medium.

c. Set pressure test: valve pressurized with saturated steam, with the pressure rising to the valve set pressure. Valve must open at nameplate set pressure ± 1 percent.

d. Response time test: each safety/relief valve tested to demonstrate acceptable response time.

The valves were installed as received from the factory. The GE equipment specification required certification from the valve manufacturer that design and performance requirements had been met. This included capacity and blowdown requirements. The set points were adjusted, verified and indicated on the valves by the vendor. In addition, ASME certified Boiler Inspectors performed independent inspections and reviews for manufacturer's compliance to ASME requirements. Customer reviews and inspections of the manufacturer further ensured achievement of compliance to the specification requirements. Specified manual and automatic actuation relief mode of each safety/relief valve was verified during the pre-operational testing program.]

The valves are mounted on 1500-lb primary service rating flanges. They can be removed for maintenance or bench checks and replaced or reinstalled during refueling outages or other plant shutdowns.

A sample population of the installed valves are removed and tested for set pressure verification at refueling outages or other cold shutdowns during each refueling cycle. This sample population is based on current Grand Gulf ASME code requirements.

a. Removed valves are reinstalled or replaced with spares which have been tested and inspected as described below.

b. Testing for as found set pressure verification is performed on the removed valves.

   1. By the end of the refueling outage, if the valves are removed during a refueling outage, or

2. Within 12 months following removal or by the end of the following refueling outage, whichever occurs first, if the valves are removed during a non-refueling outage.

c. All testing, acceptance and corrective actions shall be in accordance with the ASME OM Code for Operation and Maintenance of Nuclear Power Plants.

d. Inlet and outlet flange pressure boundary bolting will be inspected when the valves are removed for testing. Other pressure boundary bolting will be inspected when the valves are disassembled for refurbishment.

All valves will be tested and inspected prior to installation in the plant for:

a. Set pressure certification in accordance with the ASME OM Code for Operation and Maintenance of Nuclear Power Plants.

b. Pneumatic actuator leak tests

c. Mainseat leakage including any necessary seat relapping.

d. d.Visual inspection of external surfaces and parts for anomalies.

e. Visual inspection of accessible internal surfaces and parts for anomalies on fully assembled valves.

After 6 years of service life (defined as actual time installed in the plant including periods of plant shutdown) the valves will under go the following prior to reinstallation in the plant.

a. Disassembly and inspection of internals (not normally accessible for inspection) for anomalies, damage or erosion.

b. Replacement of all gaskets, seals and other parts necessary due to inspection results.

c. Lubrication of valve.

5.2.2.11 Surveillance Program

The safety/relief valve surveillance program monitors the performance of the safety/relief valves throughout the service life of each valve. It is implemented through the GGNS Inservice Testing Program, which is in compliance with the ASME Operation and Maintenance Code, Mandatory Appendix I, Edition and Addenda as specified in the GGNS IST Plan.

5.2.3 Reactor Coolant Pressure Boundary Materials

5.2.3.1 Material Specifications

Table 5.2-4 lists the principal pressure-retaining materials and the appropriate material specifications for the reactor coolant pressure boundary components.

5.2.3.2 Compatibility with Reactor Coolant

5.2.3.2.1 PWR Chemistry of Reactor Coolant

Not applicable to BWRs.

5.2.3.2.2 BWR Chemistry of Reactor Coolant

The coolant chemistry requirements discussed in this subsection are consistent with the requirements of Regulatory Guide 1.56.

Materials in the primary system are primarily Type-304 stainless steel and Zircaloy cladding. The reactor water chemistry limits are established to provide an environment favorable to these materials. Limits are placed on conductivity and chloride concentrations. Conductivity is limited because it can be continuously and reliably measured and gives an indication of abnormal conditions and the presence of unusual materials in the coolant. Chloride limits are specified to prevent stress corrosion cracking of stainless steel (Ref. 2).

[HISTORICAL INFORMATION] [Several investigations have shown that in neutral solutions some oxygen is required to cause stress corrosion cracking of stainless steel, while in the absence of oxygen no cracking occurs. One of these is the chloride-oxygen relationship of Williams (Ref. 3), where it is shown that at high chloride concentration little oxygen is required to cause stress corrosion cracking of stainless steel, and at high oxygen concentration little chloride is required to cause cracking.

These measurements were determined in a wetting and drying situation using alkaline-phosphate-treated boiler water and, therefore, are of limited significance to BWR conditions. They are, however, a qualitative indication of trends.

The water quality requirements are further supported by GE stress corrosion test data summarized as follows:

- o Type 304 stainless steel specimens were exposed in a flowing loop operating at 537 F. The water contained 1.5 ppm chloride and 1.2 ppm oxygen at pH 7. Test specimens were bent beam strips stressed over their yield strength. After 2100 hours' exposure, no cracking or failures occurred.

- o Welded Type-304 stainless steel specimens were exposed in a refreshed autoclave operating at 550 F. The water contained 0.5 ppm chloride and 1.5 ppm oxygen at pH 7. Uniaxial tensile test specimens were stressed at 125 percent of their 550 F yield strength. No cracking or failures occurred at 15,000 hours' exposure.]

When conductivity is in its normal range, pH, chloride, and other impurities affecting conductivity will also be within their normal range. When conductivity becomes abnormal, chloride measurements are made to determine whether or not they are also out of their normal operating values. Conductivity could be high due to the presence of a neutral salt which would not have an effect on pH or chloride. In such a case, high conductivity alone is not a cause for shutdown. In some types of water-cooled reactors, conductivities are high because of the purposeful use of additives. In BWRs, however, where no additives are used and where near neutral pH is maintained, conductivity provides a good and prompt measure of the quality of the reactor water. Significant changes in conductivity provide the operator with a warning mechanism so he can investigate and remedy the condition before reactor water limits are reached. Methods available to the operator for correcting the off-standard condition included operation of the reactor water cleanup system, reducing the input of impurities, and placing the reactor in the cold shutdown condition. The major benefit of cold shutdown is to reduce the temperature dependent corrosion rates and provide time for the cleanup system to reestablish the purity of the reactor coolant.

The following is a summary and description of BWR water chemistry for various plant conditions:

a. Normal Plant Operation:

1. Normal Water Chemistry

The BWR system water chemistry is conveniently described by following the system cycle as shown on Figure 5.2-14. Reference to Table 5.2-6 has been made as numbered on the diagram and correspondingly in the table.

For normal operation starting with the condenser hotwell, condensate water is processed through a condensate treatment system. This process consists of filtration and demineralization, resulting in effluent water quality represented in Table 5.2-6.

The effluent from the condensate treatment system is pumped through the feedwater heater train and enters the reactor vessel at an elevated temperature and with a chemical composition typically as shown in Table 5.2-6.

During normal plant operation, boiling occurs in the reactor, decomposition of water takes place due to radiolysis, and oxygen and hydrogen gas is formed. Due to steam generation, stripping of these gases from the water phase takes place, and the gases are carried with the steam through the turbine to the condenser. The oxygen level in the steam, resulting from this stripping process, is typically observed to be about 20 ppm (see Table 5.2-6). At the condenser, deaeration takes place and the gases are removed from the process by means of steam jet air ejectors.

The deaeration is completed to a level of approximately 20 ppb (0.02 ppm) oxygen in the condensate.

The dynamic equilibrium, in the reactor vessel water phase, established by the steam-gas stripping and the radiolytic formation (principally) rates, corresponds to a nominal value of approximately 200 ppb (0.2 ppm) of oxygen at rated operating conditions. Slight variations around this value have been observed as a result of differences in neutron flux density, coreflow and recirculation flow rate.

A reactor water cleanup system is provided for removal of impurities resulting from fission products formed in the primary system. The cleanup process consists of filtration and ion exchange and serves to maintain a high level of water purity in the reactor coolant.

Typical chemical parametric values for the reactor water are listed in Table 5.2-6 for various plant conditions.

Additional water input to the reactor vessel originates from the control rod drive (CRD) cooling water. The CRD water is essentially feedwater quality. Separate filtration for purification and removal of insoluble corrosion products takes place within the CRD system prior to entering the drive mechanisms and reactor vessel.

No other inputs of water or sources of oxygen are present during normal plant operation. During plant conditions other than normal operation, additional inputs and mechanisms are present as outlined in the following section.

2. Hydrogen Water Chemistry

The system cycle is the same as for normal water chemistry operation as discussed above, with the exception of dissolved oxygen concentrations. Injection of excess free hydrogen into reactor feedwater shifts the stoichiometric oxygen concentration in the reactor vessel to near zero concentrations. This results in a near zero

concentration of oxygen transported in the main steam to the condenser with corresponding reductions in offgas and condensate system oxygen levels. The hydrogen water chemistry system as discussed in Section 9.5.10 provides oxygen injection into both of these systems to restore the desired oxygen levels to normal water chemistry concentrations.

Section 12.1.3 provides a discussion of ALARA impacts due to hydrogen water chemistry.

b. Plant Conditions Outside Normal Operation:

During periods of plant conditions other than normal power production, transients take place, particularly with regards to the oxygen levels in the primary coolant. Systems other than the reactor are not affected significantly to impact primary system components or subsequent operation. In essence, depending on what the plant condition is, (i.e., hot standby with/without reactor vessel venting or plant shutdown) the hotwell condensate will absorb oxygen from the air when vacuum is broken on the condenser. Prior to startup and input of feedwater to the reactor, vacuum is established in the condenser and deaeration of the condensate takes place by means of mechanical vacuum pump and steam jet air ejector operation and condensate recirculation. During these plant conditions, continuous input of control rod drive (CRD) cooling water takes place as described previously.

1. Plant Depressurized and Reactor Vented

During certain periods such as during refueling and maintenance outages, the reactor is vented to the condenser or atmosphere. Under these circumstances the reactor cools and the oxygen concentration increases to a maximum value of 8 ppm. Equilibrium between the atmosphere above the reactor water surface, the CRD cooling water input, any residual radiolytic effects, and the bulk reactor water will be established after some time. No other changes in water chemistry of significance take place during this plant condition because no appreciable inputs take place.

2. Plant Transient Conditions - Plant Startup/ Shutdown

During these conditions, no significant changes in water chemistry other than oxygen concentration take place.

(a) Plant Startup

Depending on the duration of the plant shutdown prior to startup and whether the reactor has been vented, the oxygen concentration could be that of air saturated water, i.e., ~8 ppm oxygen.

Following nuclear heatup initiation, the oxygen level in the reactor water will decrease rapidly as a function of water temperature increase and corresponding oxygen solubility in water. The oxygen level will reach a minimum of about 20 ppb (0.02 ppm) at a coolant temperature of about 380 F, at which point an increase will take place due to significant radiolytic oxygen generation. For the elapsed process up to this point the oxygen is degassed from the water and is displaced to the steam dome above the water surface.

Further increase in nuclear power increases the oxygen generation as well as the temperature. The solubility of oxygen in the reactor water at the prevailing temperature controls the oxygen level in the coolant until rated temperature (~540 F) is reached. Thus, a gradual increase from the minimum level of 20 ppb to a maximum value of about 200 ppb oxygen takes place. At and after this point (540 F), steaming and the radiolytic process control the coolant oxygen concentration to a level of around 200 ppb.

(b) Plant Shutdown

Upon plant shutdown following power operation, the radiolytic oxygen generation essentially ceases as the fission process is terminated. Because oxygen is no longer generated, while some steaming still will take place due to residual energy, the oxygen concentration in the coolant will decrease to a minimum value determined by steaming rate temperature. If venting is performed, a gradual increase to essentially oxygen saturation at the coolant temperature will take place, reaching a maximum value of <8 ppm oxygen.

(c) Oxygen in Piping and Parts Other Than the Reactor Vessel Proper

As can be concluded from the preceding descriptions, the maximum possible oxygen concentration in the reactor coolant and any other directly related or associated parts is that of air saturation at ambient temperature. At no time or location, in the water phase, will oxygen levels exceed the nominal value of 8 ppm. As temperature is increased and hence, oxygen solubility decreased accordingly, the oxygen concentration will be maintained at this maximum value, or reduced below it depending on available removal mechanisms, i.e., diffusion, steam stripping, flow transfer, or degassing.

Depending on the location, configuration, etc., such as dead legs or stagnant water, inventories may contain ~8 ppm dissolved oxygen or some other value below this maximum limitation.

Conductivity is continuously monitored on the primary coolant with instruments connected to redundant sources, the reactor water recirculation loop, and the reactor water cleanup system inlet. The effluent from the reactor water cleanup system is also monitored for conductivity on a continuous basis. These measurements provide reasonable assurance for adequate surveillance of the reactor coolant.

Grab samples are provided, for the locations shown in Table 5.2-8, for special and noncontinuous measurements such as pH, oxygen, chloride, and radiochemical measurements.

The relationship of chloride concentration to specific conductance measured at 25 C for chloride compounds such as sodium chloride and hydrochloric acid can be calculated (Fig. 5.2-15). Values for these compounds essentially bracket values of other common chloride salts or mixtures at the same chloride concentration. Surveillance requirements are based on these relationships.

In addition to this program, limits, monitoring, and sampling requirements are imposed on the condensate, condensate treatment system, and feedwater by warranty requirements and specifications. Thus, a total plant water quality surveillance program is established providing assurance that off-specification conditions will quickly be detected and corrected.

The sampling frequency when reactor water has a low specific conductance is adequate for calibration and routine audit purposes. When specific conductance increases, and higher chloride concentrations are possible, or when continuous conductivity monitoring is unavailable, increased sampling is provided.

For the higher than normal limits of <1 µmho/cm, more frequent sampling and analyses are invoked by the coolant chemistry surveillance program (Table 5.2-6).

The primary coolant conductivity monitoring instrumentation, ranges, accuracy sensor, and indicator locations are shown in Table 5.2-8. The sampling is coordinated in a reactor sample station especially designed with constant temperature control and sample conditioning and flow control equipment.

3. Water Purity During a Condenser Leakage

The condensate cleanup system is designed to maintain the reactor water chloride concentration below 200 ppb during a condenser tube leak of 50 gallons per minute for one hour in a seawater-cooled plant. Equivalent system capability is available in plants with cooling water other than seawater.

To protect against a major condenser tube leak, ion exchange capacity of 25 percent of theoretical is maintained during normal operation.

5.2.3.2.3 Compatibility of Construction Materials with Reactor Coolant

The materials of construction exposed to the reactor coolant consist of the following:

a. Solution annealed austenitic stainless steels (both wrought and cast) Types 304, 304L, 316, and 316L

b. Nickel base alloys -- Inconel 600 and Inconel 750X

c. Carbon steel and low alloy steel

d. Some 400 series martensitic stainless steel (all tempered at a minimum of 1100 F)

e. Colmonoy, Stellite, and NOREM type 1 and type 2 hardfacing material.

All of these materials of construction are resistant to stress corrosion in the BWR coolant. General corrosion on all materials, except carbon and low alloy steel, is negligible. Conservative corrosion allowances are provided for all exposed surfaces of carbon and low alloy steels.

Contaminants in the reactor coolant are controlled to very low limits by the reactor water quality specifications. No detrimental effects will occur on any of the materials from allowable contaminant levels in the high purity reactor coolant. Radiolytic products in the BWR have no adverse effects on the construction materials.

5.2.3.2.4 Compatibility of Construction Materials with External Insulation and Reactor Coolant

Refer to Appendix 3A, Project Position to Regulatory Guide 1.36, regarding the use of nonmetallic insulation materials on safety-related stainless steel piping/tubing and components.

[HISTORICAL INFORMATION] [

5.2.3.3 Fabrication and Processing of Ferritic Materials

5.2.3.3.1 Fracture Toughness

5.2.3.3.1.1 Compliance with Code Requirements

The ferritic materials used for piping, pumps, and valves of the reactor coolant pressure boundary are 2-1/2 in. or less in thickness. Impact testing will be performed in accordance with NB-2332 and NB-2333 for thicknesses of 2-1/2 in. or less. Materials for bolting with nominal diameters exceeding 1 in. will be required to meet both the 25 mils lateral expansion specified in NB-2333 and the 45 ft/lb Charpy V value specified in Appendix G of 10 CFR 50.

5.2.3.3.2 Control of Welding

5.2.3.3.2.1 Control of Preheat Temperature Employed for Welding of Low Alloy Steel (Regulatory Guide 1.50)

The use of low alloy steel is restricted to the reactor pressure vessel. Other ferritic components in the reactor coolant pressure boundary are fabricated from carbon steel materials.

Preheat temperatures employed for welding of low alloy steel meet or exceed the recommendations of ASME Section III, subsection NB. Components were either held for an extended time at preheat temperature to assure removal of hydrogen, or preheat was maintained until post weld heat treatment. The minimum preheat and maximum interpass temperatures were specified and monitored.

All welds were nondestructively examined by radiographic methods. In addition, a supplemental ultrasonic examination was performed.

5.2.3.3.2.2 Control of Electroslag Weld Properties (Regulatory Guide 1.34)

No electroslag welding was performed on BWR components.

5.2.3.3.2.3 Welder Qualification for Areas of Limited Accessibility (Regulatory Guide 1.71)

There are few restrictive welds involved in the fabrication of BWR pressure boundary components. Welder qualification for welds with the most restricted access was accomplished by mock-up welding. Mock-ups were examined with radiography or sectioning.

5.2.3.3.3 Nondestructive Examination of Ferritic Tubular Products (Regulatory Guide 1.66)

Wrought tubular products were supplied in accordance with applicable ASME material specifications and examined by radiographic and/or ultrasonic methods according to Paragraph NB-2550 of ASME Code, Section III.]

[HISTORICAL INFORMATION] [

5.2.3.4 Fabrication and Processing of Austenitic Stainless Steels

5.2.3.4.1 Avoidance of Stress Corrosion Cracking

5.2.3.4.1.1 Avoidance of Significant Sensitization

All austenitic stainless steel was purchased in the solution heat treated condition in accordance with applicable ASME and ASTM specifications. Carbon content was limited to 0.08 percent maximum, and cooling rates from solution heat treating temperatures were required to be rapid enough to prevent sensitization.

Welding heat input was restricted to 110,000 joules per inch maximum, and interpass temperature to 350 F. High heat welding processes such as block welding and electroslag welding were not permitted. All weld filler metal and castings were required by specification to have a minimum of 5 percent ferrite.

Whenever any wrought austenitic stainless steel was heated to temperatures over 800 F, by means other than welding or thermal cutting, the material was re-solution heat treated.

These controls were used to avoid severe sensitization and to comply with the intent of Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel.

5.2.3.4.1.2 Process Controls to Minimize Exposure to Contaminants

Exposure to contaminants capable of causing stress corrosion cracking of austenitic stainless steel components was avoided by carefully controlling all cleaning and processing materials which contact the stainless steel during manufacture and construction.

Special care was exercised to ensure removal of surface contaminants prior to any heating operations. Water quality for cleaning, rinsing, flushing, and testing was controlled and monitored. Suitable packaging and protection was provided for components to maintain cleanliness during shipping and storage.

The degree of surface cleanliness obtained by these procedures meets the requirements of Regulatory Guides 1.44 and 1.37.

5.2.3.4.1.3 Cold Worked Austenitic Stainless Steels

Austenitic stainless steels with a yield strength greater than 90,000 psi are not used.

5.2.3.4.2 Control of Welding

5.2.3.4.2.1 Avoidance of Hot Cracking

All austenitic stainless steel filler materials were required by specification to have a minimum of 5 percent ferrite. This amount of ferrite is considered adequate to prevent hot cracking in austenitic stainless steel welds.

An extensive test program performed by GE, with the concurrence of the regulatory staff, has demonstrated that controlling weld filler metal ferrite at 5 percent minimum produces production welds which meet the requirements of Regulatory Guide 1.31, Control of Stainless Steel Welding. A total of approximately 400 production welds in five BWR plants was measured and all welds met the requirements of Interim Regulatory Position to Regulatory Guide 1.31.

5.2.3.4.2.2 Electroslag Welds. Regulatory Guide 1.34.

Electroslag welding was not employed for reactor coolant pressure boundary components.

5.2.3.4.2.3 Welder Qualification for Areas of Limited Accessibility. Regulatory Guide 1.71.

There are few restrictive welds involved in the fabrication of BWR pressure boundary components. Welder qualification for welds with the most restrictive access was accomplished by mock-up welding. Mock-ups were examined with radiography or sectioning.

5.2.3.4.3 Nondestructive Examination of Tubular Products (Regulatory Guide 1.66)

Wrought tubular products were supplied in accordance with applicable ASME material specifications and examined by radiography and/or ultrasonic methods according to Paragraph NB-2550 of ASME Code, Section III.]

5.2.3.5 Intergranular Stress Corrosion Cracking

NUREG-0313, Revision 2, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping", as implemented by NRC Generic Letter 88-01, provides a series of recommendations concerning the components used for the reactor coolant pressure boundary. The following is a summary of the configuration of Grand Gulf with regards to the recommendations of the generic letter and NUREG-0313.

5.2.3.5.1 Scope of Piping Components Included

[HISTORICAL INFORMATION] [All stainless steel piping components greater than or equal to 4" nominal diameter which contain reactor coolant at a temperature above 200 deg F[1] during power operation are subject to the recommendations of NUREG-0313, Rev. 2. At Grand Gulf this includes the following systems and component connections:

1. Reactor Recirculation System,
2. Reactor Recirculation to Reactor Water Cleanup System connections,
3. Reactor Recirculation to Residual Heat Removal System connections,
4. Reactor Pressure Vessel Nozzle connections to safe end ends and safe end connections to safe end extensions or pressure seals.

Piping made of carbon steel classified as P-1 by the ASME Boiler and Pressure Vessel Code is not included.]

[1] Design temperature was used in lieu of operating temperature to establish scope of components.

5.2.3.5.2 Methods Used to Reduce or Eliminate IGSCC

A. Selection of Materials

Materials used at GGNS which are considered to be resistant to intergranular stress corrosion cracking (IGSCC) include:

1. Low carbon ("L") grades of stainless steel base and weld material,

2. Corrosion resistant cladding on weld heat affected zones on the inside of piping weldments,

3. Solution heat treated materials,

4. Based on the provisions of the NUREG Staff Position on Inspection Schedules, cast austenitic stainless steels used at GGNS are considered to be resistant to IGSCC,

5. Reactor Pressure Vessel (RPV) safe ends and thermal sleeves which were all changed to a "tuning fork" design to eliminate crevices.

B. Processing of Materials

Special or controlled processes used at GGNS to enhance material properties and residual stresses and provide materials considered to be resistant to IGSCC include:

1. Solution heat treatment of weldments and/or corrosion resistant cladding of weldments,

2. Induction Heating Stress Improvement (IHSI) of completed weldments.

C. Hydrogen Water Chemistry

Injection of excess free hydrogen into reactor feedwater shifts the stoichiometric oxygen concentration in the reactor vessel to near zero concentrations, which results in a lower vessel water electrochemical corrosion potential (ECP) value. Laboratory and in-situ tests have shown that reduction of the reactor water ECP below-230 mV standard hydrogen electrode results in reduced susceptibility of lower core internal components to initiate stress corrosion cracking (SCC) or propagate existing cracks. However, any reduction of the reactor water ECP levels below the normal water chemistry value of +50 will provide some mitigation of SCC of reactor vessel internal materials.

Control of water quality consistent with the Electric Power Research Institute BWR Water Chemistry Guidelines - 2004 Revision, is provided to maximize the effectiveness of the hydrogen water chemistry system in mitigating the occurrence of SCC in the lower vessel regions.

The hydrogen water chemistry system provides hydrogen injection to the condensate stream as described. Section 12.1.3 provides discussion of ALARA impacts due to hydrogen water chemistry.

5.2.3.5.3 Inspection of Piping for IGSCC

A. Examination Categories

In accordance with NUREG-0313, Rev. 2, Section 5.3.1, Condition Categories have been established for stainless steel weldments at GGNS based on the degree of IGSCC susceptibility associated with the materials and processing involved. Weldments are currently assigned to four of the seven possible categories:

<u>Category A Welds</u>

IGSCC Category A weldments are those with no known cracks that have a low probability of experiencing GSCC because they are made entirely of IGSCC resistant materials or have been solution heat treated after welding. Corrosion resistant clad is considered to be IGSCC resistant, and welds joining cast pump and valve bodies to resistant piping are considered to be resistant weldments.

Materials that satisfy this definition are austenitic stainless steels that have a carbon content below 0.035% (e.g., 304L, 316L, and 316NG). Cast austenitic stainless steels, like that used for pump casings and valve bodies, with low carbon(<0.035%) and high ferrite (minimum of 7.5 FN) are Category A materials. Austenitic stainless steel that was solution heat treated after welding or that has been protected by a corrosion resistant clad is also considered resistant. Additionally, Inconel 82 and low carbon weld metals with controlled ferrite (such as 308L) are resistant.

Castings with a carbon content higher than 0.035% are generally not considered resistant to sensitization. However, experience has shown that welds joining these castings to resistant piping have performed well and can therefore be included in Category A. If extensive weld repairs were performed, the weld should be included in the Category D population.

Category B Welds

IGSCC Category B weldments are those not made of resistant materials, but that have been treated by a stress improvement (SI) process either before service or within 2 years of operation. If the stress improvement is performed after plant operation, a post-SI ultrasonic examination is required to ensure that the welds are not cracked.

The NRC staff position in Generic Letter 88-01 is that either induction heat stress improvement (IHSI) or the mechanical stress improvement process (MSIP) would upgrade material and reduce IGSCC susceptibility.

Category C Welds

IGSCC Category C weldments are those not made of resistant materials that have been given an SI process after more than 2 years of operation. As part of the process, a UT examination is required after the SI treatment to ensure the weldment is not cracked.

Category D Welds

IGSCC Category D weldments are those not made with resistant materials and not given an SI treatment, but that have been examined by personnel using procedures in conformance with Section 5.2.1 of NUREG-0313, Rev. 2 (i.e.,NDE Coordination Plan or PDI Program) and found to be free of cracks. As noted above, welds with extensive repairs that join resistant materials and castings should also be included in Category D.

Category E Welds

IGSCC Category E weldments are those with known cracks that have been reinforced by an acceptable weld overlay or have been mitigated with an SI treatment with subsequent examination by qualified examiners and procedures to verify the extend of cracking. Guidelines for acceptable weld overlay reinforcement and the extent of cracking considered amenable to SI treatment are covered in Section 3.2 and 4.5 of NUREG-0313, Rev. 2.

The staff initially considered the overlay a short-term option, but noted in Generic Letter 88-01 that it could be considered for longer term operation provided the overlays were in accordance with the criteria of IWB-3600 of the 1986 Edition of Section XI and are examined in accordance with staff recommendations. In time, the overlay came to be accepted as a long term repair option, was approved by ASME in Code Case N-504 and endorsed by the NRC.

Use of stress improvement to mitigate cracked welds is limited to welds with minor cracking. Generic Letter 88-01 specifies that SI could be used for welds with cracks no longer than 10% of the circumference and no deeper than 30% of the wall thickness.

A summary of Categories and the quantity of welds included is shown below:

Category A	303 welds
Category B	24 welds
Category C	33 welds
Category E	1 weld

There are currently no Category D, F or G weldments at GGNS.

B. Inservice Inspection Frequency and Sample Size

Examinations and examination schedules will be performed in accordance with the requirements of ASME Section XI with relief as provided for in 10CFR50.55a(g)5, and the augmented requirements of Generic Letter 88-01 and BWRVIP-75-A.

C. Inservice Inspection Methods and Personnel

GGNS will examine IGSCC susceptible welds in accordance with ASME Section XI. These examinations will be augmented with PDI, (Performance Demonstration Initiative) certified IGSCC examiners.

D. Leak Detection

The GGNS leak detection system compliance with Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems" is described in Subsection 7.6.2.4.2.1.

5.2.4 In-service Inspection and Testing of Reactor Coolant Pressure Boundary

In-service inspection of Class 1 pressure retaining components, such as vessels, piping, pumps, valves, and bolting, and supports within the reactor coolant pressure boundary, will comply with Section XI of the ASME Code, including addenda per 10 CFR 50.55a(g), with certain exceptions whenever specific written relief is granted by the NRC per 10 CFR 50.55(g)(6)i.

The inservice testing of Class 1 valves to requirements of the ASME OM Code for Operation and Maintenance of Nuclear Power Plants, is discussed in subsection 3.9.6. No Class 1 pumps have been identified that require inservice testing to the requirements of ASME OM Code.

[HISTORICAL INFORMATION] [The initial preservice inspection (PSI) of Unit 1 ASME Class 1 components has been performed in accordance with ASME Section XI, 1977 Edition, up to and including the Summer 1978 Addenda, and augmented examinations established by the Commission. PSI results have been submitted to the NRC.

Request for relief from ASME Section XI requirements identified during the initial PSI of Unit 1 were accepted by the NRC based on the considerations in Safety Evaluation Report Supplements 2 and 4, Appendix D, (NUREG-0831) and letter from the NRC dated October 16, 1985 (MAEC-85/0346).

The Inservice Inspections for the first 10-year inspection interval were in accordance with the ASME Boiler and Pressure Vessel Code, Section XI, 1977 Edition, up to and including the Summer 1979 Addenda. Portions of the 1980 Edition, Winter 1980 Addenda were utilized for the first 10-year inspection interval.

Inservice Inspections for the second inspection interval were in accordance with the ASME Boiler and Pressure Vessel Code, Section XI, Edition and Addenda as specified in the Site ISI Plan, GGNS-M-489.1.]

Inservice Inspections for the third inspection interval will be in accordance with the ASME Boiler and Pressure Vessel Code, Section XI, Edition and Addenda as specified in the program section for ASME Section XI, Div. I Inservice Inspection Program.

Details of the inspection program are contained in the Program Section for ASME Section XI, Div. I Inservice Inspection Program. This specification defines the ASME Class 1 components, welds, and supports subject to inspection, including the method, extent and frequency of examination, exempt components, and relief request.

5.2.4.1 System Boundary

In addition to the reactor pressure vessel (RPV) and support skirt, components and supports within ASME Code, Section III, Class 1, boundaries are subject to the requirements of in-service inspection per ASME Code, Section XI, in particular Article IWB.

The following systems contain components and supports within the reactor coolant pressure boundary (defined as Class 1 per ASME Code, Section III) and are shown on the system piping and instrument diagrams:

Nuclear boiler system
Main steam
Feedwater
Reactor recirculation
Reactor water cleanup
Control rod drive
Reactor core isolation cooling
Standby liquid control
Low pressure core spray
High pressure core spray
Residual heat removal
Main steam isolation valve leakage control
Feedwater leakage control

5.2.4.2 Arrangement and Accessibility

5.2.4.2.1 General

During system and component arrangement design, careful attention was given to physical clearances to allow personnel and equipment to perform required inservice examinations. Access requirements of the Code have been considered in the design of components, weld joint configuration, and system arrangement. An in-service inspection program design review was undertaken to identify any exceptions to the access requirements of the Code with subsequent design modifications and/or inspection technique development to ensure Code compliance, as required, to the extent practical at this stage of plant design and construction. Additional exceptions may be identified and reported to the NRC after plant operations as specified in 10 CFR 50.55a(g)(5)(iv). Space has been provided to handle and store insulation, structural members, shielding, and similar material related to the inspection. Suitable hoists and other handling equipment have also been provided. Lighting and sources of power for the inspection equipment are installed at appropriate locations.

5.2.4.2.2 Access to Reactor Pressure Vessel

Access to the exterior surface of the reactor pressure vessel for in-service inspection is provided by removable insulation, shield wall penetration doors, and platforms. Hinged shield wall doors around large penetrations are used to gain access for remote nozzle inspection devices. A detail of these penetrations is provided in Figure 3.8-60. An annular space of about 32 in. is provided between the vessel exterior surface and the insulation interior surface to permit the insertion of remotely operated inspection devices between the insulation and the reactor vessel. The reactor pressure vessel nozzle insulation is the removable metal reflective type. This design allows sufficient clearances for the mounting of a nozzle-to-shell examination device from tracks located on the nozzle body.

Examinations performed from these tracks include the required coverage of nozzle-to-shell welds. Nozzles that are scheduled for manual examinations will not use tracks.

The vessel flange area and vessel closure head can be examined during refueling outages using manual ultrasonic techniques. With the closure head removed, access is afforded to the upper interior clad surface of the vessel by removal of a steam dryer and separator assembly. Removal of these components also enables the examination of remaining internal components by remote visual techniques. The volumetric examination of the vessel-to-flange weld and closure head-to-flange weld can be performed by applying the search units to the RPV top head areas from one side of the weld only.

The closure head is dry stored during refueling which will facilitate direct manual examination. Removable insulation will allow examination of the head welds from the outside surface. All reactor vessel nuts and washers are removed to dry storage during refueling and may be examined at that time. Selected studs will be removed to dry storage during refueling so that all the studs will be examined during the inspection interval.

Openings in the RPV support skirt are provided to permit access to the RPV bottom head for purposes of in-service examination. The examinations to be performed may utilize mechanical equipment or manual techniques and will include examinations of circumferential portions of the meridional welds, and the bottom head penetration welds, except as excluded by Section XI of the Code.

5.2.4.2.3 Access other than Reactor Pressure Vessel

The physical arrangement of other components such as piping, pumps and valves, and supports has been designed to allow personnel access to welds requiring in-service inspection. Modifications to the initial plant design have been incorporated where practical to provide proper inspection access. Removable insulation has been provided on those piping systems requiring volumetric and surface inspection. In addition, the placement of pipe hangers and supports with respect to the welds requiring inspection has been reviewed and modified where necessary to reduce the amount of plant support required in these areas during inspection. Working platforms have been provided in areas required to facilitate servicing of pumps and valves. Temporary platforms, scaffolding, and ladders will be provided to gain access to piping welds including the pipe to reactor vessel nozzle welds. Welds requiring inspection have been located to permit ultrasonic examinations from at least one side. The surface of welds within the inspection boundary has been prepared to permit effective ultrasonic examination.

5.2.4.3 Examination Techniques and Procedures

5.2.4.3.1 Deleted

5.2.4.4 Inspection Intervals

As defined in subarticle IWA-2400 of ASME Code, Section XI, the inspection interval will be 10 years. The interval may be extended by as much as one year to permit inspections to be concurrent with plant outages.

The inspection schedule shall be in accordance with IWB-2400. It is intended that in-service examinations be performed during normal plant outages such as refueling shutdowns or maintenance shutdowns occurring during the inspection interval. No examinations will be performed which require draining of the reactor vessel or removal of the core solely for the purpose of accomplishing the examinations.

5.2.4.5 Examination Categories and Requirements

The extent of the examinations performed is in accordance with ASME Code, Section XI, Table IWB-2500-1 and the methods utilized (e.g., volumetric, surface, visual) comply with Table IWB-2500-1.

In addition, pre-service inspections comply with IWB-2200.

5.2.4.6 Evaluation of Examination Results

Examination results will be evaluated to IWB-3000 with repairs based on the requirements of IWA-4000.

5.2.4.7 System Leakage and Hydrostatic Pressure Tests

System pressure tests will be conducted in accordance with IWB-5000.

5.2.5 Detection of Leakage Through Reactor Coolant Pressure Boundary

5.2.5.1 Leakage Detection Methods

The nuclear boiler leak detection system consists of temperature, pressure, and flow sensors with associated instrumentation and alarms. This system detects, annunciates, and isolates (in certain cases) leakages in the following systems:

a. Main steam lines

b. Reactor water cleanup (RWCU) system

c. Residual heat removal (RHR) system

d. Reactor core isolation cooling (RCIC) system

e. Feedwater system

f. Recirculation system

Isolation and/or alarm of affected systems and the detection methods used are summarized in Table 5.2-9.

Small leaks (5 gpm and less) are detected by temperature and pressure changes, drain pump activities and increased airborne radioactivity. Large leaks are also detected by changes in reactor water level and changes in flow rates in process lines.

The 5 gpm leakage rate is a proposed limit on unidentified leakage. The leak detection system is fully capable of monitoring flow rates of one gpm and is, thus, in compliance with Paragraph C.2 of Regulatory Guide 1.45.

See exceptions to 1.45 in Section 3A/1.45.

5.2.5.1.1 Detection of Abnormal Leakage Within Drywell

Leaks within the drywell are detected by monitoring for abnormally high pressure and temperature within the drywell, high levels and fillup rates and long pump-out times of equipment and floor drain sumps, excessive temperature difference between the inlet and outlet cooling water for the drywell coolers, increased flow rate of the cooler condensate, a decrease in the reactor vessel water level, and high levels of fission products in the drywell atmosphere. Temperatures within the drywell are monitored at various elevations. Also, the temperature of the inlet and exit air to the atmosphere is monitored. Excessive temperatures in the drywell, increased drain sump pumping rate, increased cooler condensate flow, and drywell high pressure are annunciated by alarms in the control room and, in certain cases, cause automatic isolation of the containment. In addition, low reactor vessel water level will isolate the main steam lines. The systems within the drywell share a common area; therefore, their leakage detection systems are common. Each of the leakage detection systems inside the drywell is designed with a capability of detecting leakage less than established leakage rate limits.

5.2.5.1.2 Detection of Abnormal Leakage Outside Drywell

Outside the drywell, the piping within each system connected to the RCPB monitored for leakage is in compartments or rooms, separate from other systems where feasible, so that leakage may be detected by area temperature indications or flow monitoring instruments. Each leakage detection system discussed below is designed to detect leak rates that are less than the established leakage limits. The method used to monitor for leakage for each RCPB component may be seen in Table 5.2-9.

a. Ambient and Differential Room Ventilation Temperature

   Differential temperature sensing instruments are installed in most rooms containing equipment that is part of the reactor coolant pressure boundary. These rooms are the RCIC, RHR, and most of the reactor water cleanup systems equipment rooms, and main steam line tunnel. Temperature sensors are placed in the inlet and outlet ventilation ducts or in other locations to allow the sensors to be sensitive to temperature changes in the areas being monitored. Other sensors are installed in the equipment areas to monitor ambient temperature. A differential temperature switch between each set of sensors and/or ambient temperature switch initiates an alarm when the temperature reaches a preset value. Some of these ambient temperature switches will also initiate automatic isolation of the affected systems. Annunciator and remote readouts from temperature sensors are indicated in the control room.

b. Containment Sump Flow Measurement

   Instrumentation monitors and indicates the amount of leakage into the containment floor drainage system. The normal design leakage collected in the system consists of leakage from the reactor water cleanup system and from other miscellaneous vents and drains. Normal leakage is identified during preoperational tests.

c. Visual and Audible Inspection

Accessible areas are inspected periodically. The temperature and flow indicators discussed above are monitored regularly. Any instrument indication of abnormal leakage will be investigated.

d. Differential Flow Measurement (Cleanup System Only)

Because of the arrangement of the reactor water cleanup system, differential flow measurement provides an accurate leakage detection method. The flow from the reactor vessel is compared with the flow back to the vessel. An alarm in the control room and an isolation signal are initiated when higher flow out of the reactor vessel indicates that a leak may exist.

5.2.5.2 Leak Detection Devices

a. Drywell Floor Drain Sump Measurement

The normal design leakage collected in the floor drain sump consists of unidentified leakage from the control rod drives, valve flange leakage, floor drains, closed cooling water system, and drywell cooling unit drains.

Due to the design of the floor drain system, it is unlikely that the four drywell floor drains would become clogged at the same time. These four drains are at the same elevation and are equipped with floor drain screens. There is some potential for blockage of the screens. Therefore, in order to ensure that the screens are not inadvertently blocked when the drywell is not accessible, inspections for loose debris on the drywell floor and at the drains will be performed prior to drywell closeout for reactor power operation. More extensive surveillances are not appropriate at this time due to ALARA considerations.

b. Drywell Equipment Drain Sump

The equipment drain sump collects only identified leakage. This sump receives condensate drainage from pump seal leakoff, reactor vessel head flange vent drain, and valve packing leakoff. Collection in excess of background leakage would indicate reactor coolant leakage.

Leakage is collected and routed to the drywell equipment sump via a closed drainage piping system. The discharge from the drainage piping into the sump is below the minimum water level maintained in the sump at all times. Therefore, in the event that flashing of the leakage occurs, the steam will be contained within the drainage piping and condensed by the water in the sump as the steam exits the drainage piping due to the pressure increase in the piping. The drywell equipment sump is cooled by a heat exchanger, thus ensuring that the water in the sump remains below 212 F.

The drywell equipment sump in-leakage is monitored at a frequency specified by the Technical Specifications to ensure reactor coolant system operational leakage is within the Technical Specification limits.

c. Drywell Cooler Drain

Condensate from four out of six drywell coolers is routed to the floor drain sump and is monitored by use of a flow transmitter mounted locally while having indicating and alarm instrumentation in the control room. An adjustable alarm is set to annunciate on the condensate flow rate approaching the Technical Specification limit.

d. Drywell Pressure Measurement

The drywell pressure fluctuates slightly as a result of barometric pressure changes and out-leakage. A pressure rise above the normally indicated values will indicate the presence of a leak within the drywell.

e. Drywell Temperature Measurement

The drywell cooling system circulates the drywell atmosphere through heat exchangers (air coolers) to maintain the drywell at its designed operating temperature and also provides cooling water to the air coolers. An increase in drywell atmosphere temperature would increase the temperature rise in the drywell chilled water passing through the coils of the air coolers. Thus, an increase in the drywell chilled water temperature difference between inlet and outlet to the air coolers will indicate the presence of reactor coolant or steam leakage. Also, a drywell ambient temperature rise will indicate the presence of reactor coolant or steam leakage. A temperature rise in the drywell is detected by monitoring the drywell temperature at various elevations, inlet and outlet air to the coolers, and the drywell chilled water temperature increase between inlet and outlet to the coolers.

f. Drywell Air Monitoring

The drywell air monitoring system is used to supplement the temperature, pressure, and flow variation method described previously to detect leaks in the nuclear system process barrier. The system continuously monitors the drywell atmosphere for airborne particulate and gaseous radioactivity. The sample is drawn from the drywell. A sudden increase of activity, which may be attributed to steam or reactor water leakage, is annunciated in the control room. The drywell monitoring system is designed to remain functional when subjected to the effects of the SSE (subsection 12.3.4, Airborne Radiation).

The drywell airborne radioactivity is determined from the drywell free volume, the drywell cooler fan recirculation rate, and the coolant fission and corrosion product radioactivity. Any increase more than two standard deviations above the background count rate would indicate a possible leak with a 95 percent confidence level. The total airborne radioactivity concentration above background, due to an abnormal leak and natural decay, increases essentially linearly with time for the first several hours after the beginning of a leak. As shown in Figure 5.2-18, with different percentages of failed fuel, with different amounts of background airborne radioactivity equivalent to different leakage rates of reactor coolant, and with plateout factors of 99 percent for particulates, 90 percent for iodines, and 0 percent for noble gases, a leak of 1 gpm would be detected within 1 hour and larger leaks would be detected in proportionately shorter times (exclusive of sample transport time, which remains constant). The preset alarm level will be established after the background drywell airborne radioactivity level has been determined during plant startup.

Table 5.2-9 summarizes the actions taken by each leakage detection function. The table shows that those systems which detect gross leakage initiate immediate automatic isolation. The systems which are capable of detecting small leaks initiate an alarm in the control room. The operator can manually isolate the violated system or take other appropriate action.

g. Reactor Vessel Head Closure

The reactor vessel head closure is provided with double seals with a leak-off connection between seals that is piped through a normally closed manual valve to the equipment drain sump. Leakage through the first seal is annunciated in the control room. When pressure between the seals increases, an alarm in the control room is actuated. The second seal then operates to contain the vessel pressure.

h. Reactor Water Recirculation Pump Seal

Reactor water recirculation pump seal leaks are detected by monitoring the drain line. Leakage, indicated by high flow rate, alarms in the control room. Leakage is piped to the drywell equipment drain sump.

i. Safety/Relief Valves

Temperature sensors connected to a multipoint recorder are provided to detect safety/relief valve leakage during reactor operation. Safety/relief valve temperature elements are mounted, using a thermowell, in the safety/relief valve discharge piping several feet from the valve body. Temperature rise above ambient is annunciated in the control room. (See the nuclear boiler system piping and instrumentation diagram, Figures 5.2-6 through 5.2-8.)

j. Valve Packing Leakage

Valve stem packing leaks of power-operated valves in the nuclear boiler system, reactor water cleanup system, high pressure core spray, low pressure core spray, reactor core isolation cooling system, residual heat removal system, and recirculation system are detected by monitoring packing leakoff for high temperature and are annunciated by an alarm in the control room.

k. High/Low Pressure Interfaces

The LPCS and RHR/LPCI are all monitored for reactor coolant system leakage into the system by pressure switches located in the pump discharge lines outside the primary containment.

These switches activate a high pressure alarm in the main control room when the line pressure exceeds its normal high value. This design concept was also applied to the RHR/shutdown cooling suction line in that a pressure switch is located on the RHR “A” pump suction. All these lines are protected by safety/ relief valves which relieve any overpressure leaking from the RCS through the outboard isolation valve by discharging to the suppression pool or adequate drain facility. The suction sides of the ECCS and RCIC pumps are also provided with thermal relief valves which relieve any overpressurization that leaks back through the check valves in the pump discharge line.

The piping between the inboard valve and outboard isolation valve is designed for full RCS design conditions (or greater) in the systems listed above. In the case of the HPCS and RCIC injection lines, the design pressure of these lines meets or exceeds the RCS design pressure upstream of the outboard isolation valve. Therefore, overpressurization of these lines has been considered in the basic design. In general, where RCS leakage would present an overpressurization problem in these systems, the leakage of other system valves, such as the pump discharge check valves, would also have to be postulated.

Valves in ECCS and RCIC systems which perform a pressure isolation function between the reactor coolant system and portions of systems with a lower design pressure, are tested in accordance with the Technical Specifications. Post-maintenance leak testing will be performed on a particular valve only when the maintenance affects the pressure retaining capability as defined by station procedures.

5.2.5.3 Indication in Control Room

Leak detection methods are discussed in subsection 5.2.5.1. Details of the leakage detection system indications are included in subsection 7.6.1.4.3. Plant operating instructions dictate the action an operator is to take upon receipt of an alarm from any leakage detection system.

5.2.5.4 Limits for Reactor Coolant Leakage

5.2.5.4.1 Total Leakage Rate

The total leakage rate consists of all leakage, identified and unidentified, that flows to the drywell floor drain and equipment drain sumps. The criterion for establishing the total leakage rate limit is based on the makeup capability of the RCIC systems and independent of the feedwater system, normal ac power, and the emergency core cooling systems. The total leakage rate limit is specified in the Technical Specifications.

The total leakage rate limit is also set low enough to prevent overflow of the drywell sumps. The equipment sump and the floor drain sump, which collect all leakage, are each drained by two 50-gpm pumps.

5.2.5.4.2 Normally Expected Leakage Rate

The pump packing glands, valve stems, and other seals in systems that are part of the reactor coolant pressure boundary and from which normal design leakage is expected are provided with drains or auxiliary sealing systems. Nuclear system valves and pumps inside the drywell are equipped with double seals. Leakage from the primary recirculation pump seals is piped to the drywell equipment drain sump. Leakage from the main steam safety/relief valves is identified by temperature sensors that transmit to the control room. Any temperature increase above the drywell ambient temperature detected by these sensors indicates valve leakage. Leakage from the reactor vessel head flange is also monitored (subsection 7.6.1.4.3.).

Thus, the leakage rates from pumps, valve seals, and the reactor vessel head seal are measurable during plant operation. These leakage rates, plus any other leakage rates measured while the drywell is open, are defined as identified leakage rates.

All leakage other than the base value will be unidentified unless it can be identified to changes in pumps, valve seals, or reactor vessel head seals. When a change in leakage has been properly identified, a new base value may be calculated with the Shift Supervisor's permission. However, maximum identified leakage rate and frequency is fixed and is governed by the Technical Specifications.

5.2.5.5 Unidentified Leakage Inside the Drywell

5.2.5.5.1 Unidentified Leakage Rate

The unidentified leakage rate is the portion of the total leakage rate received in the drywell sumps that is not identified as previously described. A threat of significant compromise to the nuclear system process barrier exists if the barrier contains a crack that is large enough to propagate rapidly (critical crack length). The unidentified leakage rate limit must be low because of the possibility that most of the unidentified leakage rate might be emitted from a single crack in the nuclear system process barrier.

An allowance for leakage that does not compromise barrier integrity and is not identifiable is made for normal plant operation.

The unidentified leakage rate limit, as specified in the Technical Specifications is established to allow time for corrective action before the process barrier could be significantly compromised. The unidentified leakage rate is a small fraction of the calculated flow from a critical crack in a primary system pipe (Figure 5.2-16). Safety limits and safety limit settings are discussed in the Technical Specifications.

5.2.5.5.2 5 Sensitivity and Response Times

Sensitivity, including response time of the leak detection system, is covered in subsection 7.6.1.4.

5.2.5.5.3 Length of Through-Wall Flaw

[HISTORICAL INFORMATION] [Experiments conducted by GE and Battelle Memorial Institute (BMI) permit an analysis of critical crack size and crack opening displacement (Ref. 4). This analysis relates to axially oriented through-wall cracks.

a. Critical Crack Length

   Both the GE and BMI test results indicate that theoretical fracture mechanics formulas do not predict critical crack length, but that satisfactory empirical expressions may be developed to fit test results. A simple equation which fits the data in the range of normal design stresses (for carbon steel pipe) is

$$\ell c = \frac{15000D}{\sigma h}$$ (see data correlation on Figure 5.2-17)

where

ℓc = critical crack length (in.)

D = mean pipe diameter (in.)

σh = nominal hoop stress (psi)

b. Crack Opening Displacement

The theory of elasticity predicts a crack opening displacement of

$$\omega = \frac{2\ell\sigma}{E}$$

where

ℓ = crack length

σ = applied nominal stress

E = Young's Modulus

Measurements of crack opening displacement made by BMI show that local yielding greatly increases the crack opening displacement as the applied stress approaches the failure stress σf. A suitable correction factor for plasticity effects is:

$$C = \sec \frac{\pi}{2} \frac{\sigma}{\sigma_f} \tag{5.2-2}$$

The crack opening area is given by

$$A = C \frac{\pi}{4} \omega\ell = \frac{\pi\ell^2\sigma}{2E} \sec \frac{\pi}{2} \frac{\sigma}{\sigma_f} \tag{5.2-3}$$

For a given crack length ℓ, $\sigma f = 15{,}000\ D/\ell$.

c. Leakage Flow Rate

The maximum flow rate for blowdown of saturated water at 1000 psi is 55 lb/sec-in.^{2} and for saturated steam the rate is 14.6 lb/sec-in.^{2}, (Ref. 5). Friction in the flow passage reduces this rate, but for cracks leaking at 5 gpm (0.7 lb/sec) the effect of friction is small. The required leak size for 5 gpm flow is

A = 0.0126 in.^{2} (saturated water)

A = 0.0475 (saturated steam)

From this mathematical model, the critical crack length and the 5-gpm crack length have been calculated for representative BWR pipe size (Schedule 80) and pressure (1050 psi).

The lengths of through-wall cracks that would leak at the rate of 5 gpm given as a function of wall thickness and nominal pipe size are:

Nominal Pipe Size (Sch 80), in.	Average Wall Thickness, in.	Crack Length ℓ in. Steam Line	Crack Length ℓ in. Water Line
4	0.337	7.2	4.9
12	0.687	8.5	4.8
24	1.218	8.6	4.6

The ratios of crack length, ℓ, to the critical crack length, ℓc as a function of nominal pipe size are:

Nominal Pipe Size (Sch 80), in.	Ratio ℓ/ℓ_c Steam Line	Ratio ℓ/ℓ_c Water Line
4	0.745	0.510
12	0.432	0.243
24	0.247	0.132

It is important to recognize that the failure of ductile piping with a long, through-wall crack is characterized by large crack opening displacements which precede unstable rupture. Judging from observed crack behavior in the GE and BMI experimental programs, involving both circumferential and axial cracks, it is estimated that leak rates of hundreds of gpm will precede crack instability. Measured crack opening displacements for the BMI experiments were in the range of 0.1 to 0.2 in. at the time of incipient rupture, corresponding to leaks of the order of 1 in. in size for plain carbon steel piping. For austenitic stainless steel piping, even larger leaks are expected to precede crack instability, although there are insufficient data to permit quantitative prediction.

The results given are for a longitudinally oriented flaw at normal operating hoop stress. A circumferentially oriented flaw could be subjected to stress as high as the 550 F yield stress, assuming high thermal expansion stresses exist. A good mathematical model, which is well supported by test data, is not available for the circumferential crack. Therefore, it is assumed that the longitudinal crack, subject to a stress as high as 30,000 psi, constitutes a “worst case” with regard to leak rate versus critical size relationships. Given the same stress level, differences between the circumferential and longitudinal orientations are not expected to be significant in this comparison.

Figure 5.2-16 shows general relationships between crack length, leak rate, stress, and line size, using the mathematical model described previously. The asterisks denote conditions at which the crack opening displacement is 0.1 in., at which time instability is imminent, as noted previously under “Leakage Flow Rate.” This provides a realistic estimate of the leak rate to be expected from a crack of critical size. In every case, the leak rate from a crack of critical size is significantly greater than the 5-gpm criterion.

If either the total or unidentified leak rate limits are exceeded, plant operations would be governed by the appropriate Technical Specification requirement.]

5.2.5.5.4 Margins of Safety

The margins of safety for a detectable flaw to reach critical size are presented in subsection 5.2.5.5.3. Figure 5.2-16 shows general relationships between crack length, leak rate, stress, and line size using the mathematical model.

5.2.5.5.5 Criteria to Evaluate the Adequacy and Margin of the Leak Detection System

For process lines that are normally open, there are at least two different methods of detecting abnormal leakage from each system within the nuclear system process barrier located in the drywell, containment, and auxiliary building as shown in Table 5.2-9. The instrumentation is designed so it can be set to provide alarms at established leakage rate limits and isolate the affected system, if necessary. The alarm points are determined analytically or based on measurements of appropriate parameters made during startup and preoperational tests.

The unidentified leakage rate limit is based, with an adequate margin for contingencies, on the crack size large enough to propagate rapidly. The established limit is sufficiently low so that, even if the entire unidentified leakage rate were coming from a single crack in the nuclear system process carrier, corrective action could be taken before the integrity of the barrier would be threatened with significant compromise.

The leak detection system will satisfactorily detect unidentified leakage of 1 gpm.

Sensitivity, including sensitivity testing and response time of the leak detection system, and the criteria for shutdown if leakage limits are exceeded, are covered in subsection 7.6.1.4.

5.2.5.6 Differentiation Between Identified and Unidentified Leaks

Subsection 5.2.5.1 describes the systems that are monitored by the leak detection system. The ability of the leak detection system to differentiate between identified and unidentified leakage is discussed in subsections 5.2.5.1, 5.2.5.5, and 7.6.1.4.

5.2.5.7 Sensitivity and Operability Tests

Testability of the leakage detection system is contained in Section 7.6.

5.2.5.8 Safety Interfaces

The balance of plant-GE nuclear steam supply system (NSSS) safety interfaces for the leak detection system are the signals from the monitored balance of plant equipment and systems which are part of the nuclear system process barrier, and all associated wiring and cable lying outside the NSSS. This balance of plant systems and equipment includes the main steam line tunnel, the safety/relief valves, and the turbine building sumps.

5.2.5.9 Testing and Calibration

Pressure, differential pressure, and other process transmitters in the leak detection system will be calibrated by injecting a simulated process signal that is monitored by a calibrated instrument of appropriate range and accuracy.

Analog trip units will be calibrated by injecting a test current from a calibration unit and monitored by a digital read out unit. Calibration will include all trip set points and analog devices.

Operability will be verified by the performance of channel checks at the frequency specified in the Technical Specifications.

Tests will be performed periodically to verify trip set points and output functions as per the Technical Specifications.

5.2.6 Loading and Stress Analysis Methods

5.2.6.1 RCPB Components Designed by Stress Analysis

The loading conditions for pressure containing components of the RCPB may be divided into four categories: normal, upset, emergency, and faulted conditions. These categories are generally described in Winter 1972 Addenda of 1971 ASME Code, Section III, Paragraph NB 3113. A summary of the number of cycles for transients used in design and fatigue analysis is listed in Table 5.2-11 and categorized under the appropriate design condition (i.e., normal, upset, emergency, and faulted).

5.2.6.2 Components Designed Primarily by Empirical Methods

There are some structural and electrical nonpressure-containing stress analysis techniques. Simple stress analyses are sometimes used to augment the design of these components, but the primary design work does not depend upon detailed stress analysis. These components are usually designed from tests and empirical data. Field experience and testing are used to support the design. Where the structural or mechanical integrity of components is essential to safety, the components referred to in these criteria must be designed to accommodate the events of the safe shutdown earthquake, or a design basis pipe rupture, or a combination of these events where appropriate. The reliability requirements of such components cannot be quantitatively described in a general specific function in the system.

5.2.6.3 Reactor Vessel

The reactor vessel is designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III, its interpretations, and applicable requirements for Class A vessel as defined therein, as of the order date of December, 1972. The vessel was subsequently upgraded to the 1971 edition with Winter 1972 Addenda.

Both elastic and inelastic stress analysis techniques may be used in the design of the reactor vessel core support and reactor internal structures to show that stress limits are not exceeded. In the event that an inelastic stress analysis is performed on these components, the elastic (linear) system analysis will be checked to see if the analysis requires modification. The procedure is to perform a linear analysis with the stiffness of the inelastic component reduced to the stiffness value corresponding to the inelastic displacement value. A nonlinear dynamic analysis will be performed in lieu of a linear analysis if the natural frequencies of the stiffness deviate significantly from that of the unreduced system.

The vessel is designed for a useful life of 40 years. Table 5.2-1 gives the applicable Code Cases.

5.2.6.4 Stress and Pressure Limits

Paragraphs NB-3655 and NB-3656 of ASME Section III are not directly applicable to pumps and valves. On the basis of the utilized method of establishing design pressures, however, it can be stated that the requirements of NB-3655.1 and NB-3656.1 are met.

The allowable stress limits and design loads for RCPB components are listed in Table 3.9-2. Active or inactive components of the RCPB are delineated in Table 5.2-5.

5.2.6.5 Stress Analysis for Structural Adequacy

Stress analysis was used to determine structural adequacy of pressure components of the reactor coolant pressure boundary under various operating conditions and earthquakes.

Significant discontinuities, such as nozzles, flanges, etc., were considered. In addition to the design calculations required by the ASME Codes, stress analysis was performed by methods outlined in the Code appendices or by other methods applicable to the design condition through reference to analogous codes or other published literature.

5.2.6.6 Analysis Method for Faulted Condition

Except when qualified by experimental methods, elastic stress analysis methods in conjunction with elastic system analysis were generally used for reactor coolant pressure boundary components. In the event that an inelastic stress analysis is performed, the elastic (linear) system analysis was checked.

5.2.6.7 Protection Against Environmental Factors

The design requirements established to protect the principal components of the reactor coolant system against environmental effects are discussed in Section 3.11. Missile protection is discussed in Section 3.5. Protection against fire is discussed in Section 9.5.

5.2.6.8 Compliance with Code Requirements

For components that are constructed in accordance with Section III of the ASME Code, Subsection NB, analytical calculations or experimental testing is performed to demonstrate compliance with the Code. In addition, brief descriptions of the mathematical or test models and the methods of calculation or testing, including any simplifying assumptions with summary of results, are provided in Section 3.9.

5.2.6.9 Stress Analysis for Emergency and Faulted Condition Loadings

The types of loads that will be evaluated for the emergency and faulted conditions are given in Table 3.9-2 for selected components.

5.2.6.10 Stress Levels in Seismic Category I Systems

Seismic analysis of seismic Category I components of the RCPB are analyzed in accordance with code requirements and the results are documented in Table 3.9-2.

5.2.6.11 Analytical Methods for Stresses in Pumps and Valves

The methods and criteria for analysis of stresses and deformations in the pressure boundary portions of Class I pumps are in accordance with ASME Code, Section III.

The methods and criteria for design and acceptability of stresses and deformations, as determined for the pressure boundary portions of Class I line valves and safety/relief valves, are those described in the applicable portions of NB-3500 of Section III.

In the event that components are supplied with geometries or design conditions for which Code Limits have not been developed, a complete description of the analytical methods and criteria used for evaluation of stresses and deformations was submitted by the manufacturer to the applicant and/or his authorized agent.

The summary of the detailed analyses for the RCPB components (analytical modes, methods of calculation, and a summary of results) is provided in Table 3.9-2.

5.2.7 References

1. Linford, R., "Analytical Methods of Plant Transient Evaluation for the General Electric Boiling Water Reactor," NEDO-10802, April 1973.

2. Skarpelos, J.M., and Bagg, J.W., "Chloride Control in BWR Coolants," NEDO-10899, June 1973.

3. Williams, W.L., Corrosion, Vol 13, 1957, p. 539t.

4. Reynolds, M.B., "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," GEAP-5620, April 1968.

5. "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants," NUREG-75/067, NRC/PCSG, October 1975.

6. "Qualification of the One-Dimensional Core Transient Model for BWR," NEDO-24154, October 1978.

TABLE 5.2-1: REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS CODE CASE INTERPRETATIONS

1.	1141-1	Foreign Produced Steel
2.	1332-6	Requirements for Steel Forgings
3.	1334-3	Requirements for Corrosion Resisting Steel Bars and Shaping
4.	1335-9, 1335-10	Requirements for Bolting Materials Section III
5.	1337-10	Requirements for Special Type 403 Modified Forgings and Bars
6.	1344-5	Requirements for Nickel-Chromium, Age Hardenable Alloys, Section III
7.	1384-2	Requirements for Precipitation Hardening Alloy Bars and Forgings, Section III
8.	1388-1, 1388-2	Requirements for Stainless Steel Precipitation Hardening, Section III
9.	1390-2	Requirements for Nickel-Chromium Age Hardenable Alloy for Bolting, Section III
10.	1401-1	Welding Repairs to Cladding of Class I, Section III, Components After Heat Treating
11.	1433-1	Normalized and Tempered 2-1/4 and 3A Low Alloy Forgings
12.	1434-1	Postweld Heat Treatment of SA-487 Class 8N Castings
13.	1456-2	Substitution of U.T. Examination for Progressive PT or MT of Partial Penetration and Oblique Nozzle Attachment.
14.	1487	Evaluation of Nuclear Piping for Faulted Conditions
15.	1492	Postweld Heat Treatment, Sections I, III, and VIII, Div. 1 and 2
16.	1506	Stress Intensification Factors, Section III, Classes 2 and 3, Piping

TABLE 5.2-1: REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS CODE CASE INTERPRETATIONS (CONTINUED)

17.	1508	Allowable Stresses, Design Stress Intensity, and/or Yield Strength Values, Sections I and VIII, Divisions 1 and 2
18.	1516-1	Welding of Seats or Minor Internal Permanent Attachments in Valves for Section III application.
19.	1535	1535 Hydro Testing, Section 3, Class 1 Valves
20.	1541-1, 1541-3	Hydrostatic Testing of Embedded Class 2 and 3 Piping for Section III Construction
21.	1557-1	Steel Product Refined by Section Melting
22.	1562	Qualification of Forming and Bending Procedures for Class 1, 2, and 3 Components
23.	1567	Testing Lots of Carbon and Low Alloy Steel Covered Electrodes
24.	1572	Fracture Toughness, Section Class 1 Components
25.	1578	SB 167 Nickel Chrome Iron (Alloy 600) Pipe or Tube, Section III
26.	1580-1	Butt-welded Alignment Tolerances and Acceptable Slopes for Concentric Centerlines for Section III, Classes 1, 2, and 3.
27.	1586(N46)	Electro-Etching of Section III Code Symbols
28.	1620	Stress Category for Partial Penetration Welded Penetration Section III, Class 1 Construction
29.	1622	PWHT of Repair Welds in Carbon Steel Castings, Section III, Classes 1, 2, and 3
30.	1637	Effective date for Completion With NA-3700 of Section III.
31.	1644-4, 1644-5, 1644-6, 1644-7	Additional Materials for Component Supports - Section III, Subsection NF, Classes 1, 2, 3, and MC Construction (Note (1))

TABLE 5.2-1: REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS CODE CASE INTERPRETATIONS (CONTINUED)

32.	1651	Interim Requirements for Certification of Component Supports, Section III, Subsection NF.
33.	1677	Clarification of Flange Design Loads, Section III, Classes 1, 2, and 3
34.	1682, 1682-1	Alternate Rules for Material Manufacturers and Suppliers and MC Construction, Section III, Subarticle NA 3700.
35.	1683, 1683-1	Bolt Holes for Section III, Classes 1, 2, and 3, and MC Component Supports
36.	1690	Stock Materials for Section III Construction, Section III
37.	1706	Data Report Form for Component Supports, Section III, Classes 1, 2, and 3
38.	1718	Design of Structural Connections for Linear Type Component Supports, Section III, Division 1, Classes 1, 2, 3, and MC.
39.	1728	Steel Structure Shapes and Small Material Products for Component Supports, Section III, Division 1 Construction
40.	1729	Minimum Edge Distance Bolt for Section III, Division 1, Classes 1, 2, and 3 and MC Construction of Component Supports
41.	1734	Welded Design for Use for Section 3, Division 1,Classes 1, 2, and 3 and MC Construction of Component Supports
42.	1818	Welded Joints in Component Standard Supports, Section III, Division 1.
43.	1819	Use of Type XM-19 for Construction, Section III, Division 1, Classes 1, 2, and 3
44.	1820	Alternative Ultrasonic Examination Technique, Section III, Division 1.
45.	1285-2	Manganese Limit of SA-105 Forgings, Section VIII, Division 1 and 2
46.	1367-2	Heat Treatment of Steel Plate for Improved Notch Toughness

TABLE 5.2-1: REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS CODE CASE INTERPRETATIONS (CONTINUED)

47.	1444	(Annulled) - U.T. for Section VIII, Divisions 1 and 2
48.	1493-1	(Annulled) - Postweld Heat Treatment, Section III
49.	1498-1	SA-508, Classes 2 and 3, Minimum Tempering Temperature, ASME Section III
50.	1614	Hydrostatic Testing of Piping Prior to or Following the Installation of Spray Nozzles for Section III, 1, 2, and 3 Piping Systems
51.	1588	Electroetching of Section III Code Symbols
52.	N-240	Hydrostatic testing of open-ended piping
53.	N-241	Hydrostatic testing of piping
54.	N-242	Materials Certification. Note(3)
55.	N-310	Certification of Bolting Materials
56.	N-234	Time between ultrasonic calibration checks
57.	N-235	Ultrasonic calibration checks per Section
58.	N71-10	Additional materials for component supports fabricated by welding. Note (1)
	N-71-11	N-71-11 Additional Materials for Component Support Fabricated by Welding, Section III, Division 1, Subsection NF, Class 1, 2, 3, and MC Component Supports
	N-71-12	Additional Materials for Component Supports Fabricated by Welding, Section III, Division 1, Class 1, 2, 3, and MC
	N-71-13	Additional Materials for Subsection NF, Class 1, 2, 3, and MC Component Supports Fabricated by Welding, Section III, Division 1
	N-71-14	Additional Materials for Subsection NF, Class 1, 2, 3, and MC Component Supports Fabricated by Welding, Section III, Division 1
	N-71-15	Additional Materials for Subsection NF, Class 1, 2, 3, and MC Component Supports Fabricated by Welding, Section III, Division 1

TABLE 5.2-1: REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS CODE CASE INTERPRETATIONS (CONTINUED)

59.	N249-1	Additional materials for component supports fabricated without welding
60.	N-71-8	Additional Materials for Component Supports, Section III, Division 1, Subsection NF, Class 1, 2, 3 and MC Component Supports
61.	N-71-9	Additional Materials for Component Supports Fabricated by Welding, Section III, Division 1, Subsection NF, Class 1, 2, 3 and MC Component Supports
62.	N-249-2	Additional Materials for Subsection NF, Class 1, 2, 3 and MC Component Supports Fabricated Without Welding, Section III, Division 1
	N-249-3	Additional Materials for Subsection NF, Class 1, 2, 3, and MC Component Supports Fabricated without Welding, Section III, Division 1
	N-249-4	Additional Materials for Subsection NF, Class 1, 2, 3, and MC Component Supports Fabricated without Welding, Section III, Division 1
	N-249-5	Additional Materials for Subsection NF, Class 1, 2, 3, and MC Component Supports Fabricated without Welding, Section III, Division 1
	N-249-6	Additional Materials for Subsection NF, Class 1, 2, 3, and MC Component Supports Fabricated without Welding, Section III, Division 1
	N-249-7	Additional Materials for Subsection NF, Class 1, 2, 3, and MC Component Supports Fabricated without Welding, Section III, Division 1
	N-249-8	Additional Materials for Subsection NF, Class 1, 2, 3, and MC Component Supports Fabricated without Welding, Section III, Division 1
	N-249-9	Additional Materials for Subsection NF, Class 1, 2, 3, and MC Component Supports Fabricated without Welding, Section III, Division 1

TABLE 5.2-1: REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS CODE CASE INTERPRETATIONS (CONTINUED)

	N-249-10	Additional Materials for Subsection NF, Class 1, 2, 3, and MC Component Supports Fabricated without Welding, Section III, Division 1
	N-249-11	Additional Materials for Subsection NF, Class 1, 2, 3, and MC Component Supports Fabricated without Welding, Section III, Division 1
63.	N247	Certified Design Report Summary for Component Standard Supports, Section III, Division 1, Class 1, 2, 3 and MC
64.	Deleted	
65.	N-411	Alternative Damping Values for Seismic Analysis of Class 1, 2, and 3 Piping Sections, Section III, Division I
66.	N-242-1	Materials Certification. Note (2)
67.	Deleted	
68.	Deleted	
69.	Deleted	
70.	Deleted	
71.	Deleted	
72.	Deleted	
73.	Deleted	
74.	Deleted	
75.	Deleted	
76.	BWRVIP-75-A: BWR Vessel and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedule	

TABLE 5.2-1: REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS CODE CASE INTERPRETATIONS (CONTINUED)

Restrictions set forth in Regulatory Guide 1.84 and 1.85 are followed as delineated in Appendix 3A.

Note (1) The maximum measured ultimate tensile strength of the component support material has not exceeded 170 ksi per Regulatory Guide 1.85.

Note (2) Components and supports requiring the use of Code Case N-242-1, Paragraph 5.5, are as follows:

ASME Section III, Subsection NF, Class 1, Hydraulic Snubbers (Main Steam and Recirculation Systems)

Note (3) Components and Supports requiring the use of Code Case N-242, Paragraph 5.5 are as follows:

ASME Section III, Subsection NF, Class 1, Hydraulic Snubbers (Main Steam and Recirculation Systems)

Note (4) Deleted

Note (5) ASME Section III Code Cases listed in Table 5.2-1 are those used in the original construction of GGNS. Other Code Cases that are adopted for use, as approved by Regulatory Guides 1.147, 1.84, 1.85 or specifically approved by the Regulatory Authority for use at GGNS, are specified in the component's design specification as required by ASME Section III NA-3250.

Note (6) ASME Section XI Code Cases approved for use at GGNS are specified in the Program Section for ASME Section XI, Div. I Inservice Inspection Program.

TABLE 5.2-2: NUCLEAR SYSTEM SAFETY/RELIEF SET POINTS

a. Set Pressures and Capacities for Spring Lift Operation

No. of Valves	Spring Set Pressure (psig)	ASME Rate Capacity at 103% Spring Set Pressure (lb/hr each)
8	1,165	895,000
6	1,180	906,000
6	1,190	913,000

b. Set Pressures for Power Actuated Relief Operation

		Low-Low Set Relief	
No. of Valves	Relief Pressure Controller Set Pressure (psig)	No of Valves	Set Point Open/Close
1	1,103*	1	1,033/926
10	1,113*	1	1,073/936
		4	1,113/946
9	1,123*	-	-

*Closing set point is 100 psi below opening set point

TABLE 5.2-2a: SAFETY/RELIEF VALVE DISCHARGE COEFFICIENTS/ CAPACITIES

Procedure and Calculations

I. Required Relief Valve Capacity

Set pressure (psig)	Capacity in lbs/hr
1130	868000 - 911000
1135	872000 - 915000
1165	895000 - 939000
1175	902000 - 947000
1180	906000 - 951000
1185	910000 - 955000
1190	913000 - 958000
1195	917000 - 962000
1205	925000 - 971000

II. Calculation

The coefficient of discharge, KD = 0.873

K = KD x 0.90 = 0.7857

W = 51.5 A P K lbs/hr

in which A = Actual discharge area in sq in

P = Set pressure times 1.03 plus atmospheric pressure in psia

Min = A = $\pi/4 \times 4.84^2$ = 18.4 sq in

Max = A = $\pi/4 \times 4.844^2$ = 18.429 sq in

TABLE 5.2-2a: SAFETY/RELIEF VALVE DISCHARGE COEFFICIENTS/ CAPACITIES (Continued)

Procedure and Calculations

III. Results

The capacities are then as follows:

For P:

a) 1.03 x 1130 + 14.7 = 1179 psia
b) 1.03 x 1135 + 14.7 = 1184 psia
c) 1.03 x 1165 + 14.7 = 1215 psia
d) 1.03 x 1175 + 14.7 = 1225 psia
e) 1.03 x 1180 + 14.7 = 1230 psia
f) 1.03 x 1185 + 14.7 = 1235 psia
g) 1.03 x 1190 + 14.7 = 1240 psia
h) 1.03 x 1195 + 14.7 = 1246 psia
i) 1.03 x 1205 + 14.7 = 1256 psia

and for W:

a) 51.5 x 18.4 x 1179 x 0.7857 = 877800 lbs/hr
b) 51.5 x 18.4 x 1184 x 0.7857 = 881522 lbs/hr
c) 51.5 x 18.4 x 1215 x 0.7857 = 904603 lbs/hr
d) 51.5 x 18.4 x 1225 x 0.7857 = 912048 lbs/hr
e) 51.5 x 18.4 x 1230 x 0.7857 = 915771 lbs/hr
f) 51.5 x 18.4 x 1235 x 0.7857 = 919493 lbs/hr
g) 51.5 x 18.4 x 1240 x 0.7857 = 923216 lbs/hr
h) 51.5 x 18.4 x 1246 x 0.7857 = 927684 lbs/hr
i) 51.5 x 18.4 x 1256 x 0.7857 = 935129 lbs/hr

TABLE 5.2-3: DESIGN TEMPERATURE, PRESSURE, AND MAXIMUM TEST PRESSURE FOR RCPB COMPONENTS

Component	Design Temperature (F)	Design Pressure (psig)	Maximum Test Pressure (psig)
Reactor Vessel	575	1250	1563
Recirculation System			
Pump Discharge Piping Through Valves	575	1650	(1)
Pump Discharge Piping Beyond Valves	575	1550	(1)
Pump Suction Piping	575	1250	(1)
Pump and Discharge Valves	575	1575	(1)
Suction Valves	575	1250	(1)
Flow Control Valve	575	1675	(1)
Vessel Drain Line	575	1250	(1)
Main Steam Line	575	1250	(1)
Main Steam Line Valves	625	1375	(3)

TABLE 5.2-3: DESIGN TEMPERATURE, PRESSURE, AND MAXIMUM TEST PRESSURE FOR RCPB COMPONENTS (Continued)

Component	Design Temperature (F)	Design Pressure (psig)	Maximum Test Pressure (psig)
Residual Heat Removal System			
Shutdown Suction			
Recirculation header to second isolation valve			
Piping	575	1250	(1)
Valves	575	1250	(2)
Pump Discharge			
Reactor vessel to second isolation valves			
Piping	575	1250	(1)
Valves	575	1250	(2)
Recirculation header to second isolation valve			
Piping	575	1500	(1)
Valves	575	1500	(2)
Reactor Feedwater			
Reactor vessel to maintenance valve in drywell			
Piping	575	1250	(1)
Valves	575	1250	(2)

TABLE 5.2-3: DESIGN TEMPERATURE, PRESSURE, AND MAXIMUM TEST PRESSURE FOR RCPB COMPONENTS (Continued)

Component	Design Temperature (F)	Design Pressure (psig)	Maximum Test Pressure (psig)
Maintenance valve to second isolation valve	575	1500	(1)
Reactor Core Isolation Cooling System			
Steam to RHR and RCIC Pump Turbine			
Reactor Vessel to Second Isolation Valve			
Piping	575	1250	(1)
Valves	575	1250	(2)
Pump Discharge to Reactor			
Reactor Vessel to Second Isolation Valve			
Piping	575	1500	(1)
Valves	575	1500	(2)
High Pressure Core Spray System			
Pump Discharge to Containment Isolation			

TABLE 5.2-3: DESIGN TEMPERATURE, PRESSURE, AND MAXIMUM TEST PRESSURE FOR RCPB COMPONENTS (Continued)

Component	Design Temperature (F)	Design Pressure (psig)	Maximum Test Pressure (psig)
Valve (Outside)	200	1575	(2)
Beyond containment isolation valve to reactor vessel			
Piping	575	1575	(1)
Valves	575	1575	(2)
Low-Pressure Core Spray System			
Pump discharge			
Reactor vessel to second isolation valve			
Piping	575	1250	(1)
Valves	575	1250	(2)
Standby Liquid Control			
HPCS line to and including system block valve (F008)			
Piping	575	1700	(1)
Valves	575 or 150	1250 or 1700	(2)

TABLE 5.2-3: DESIGN TEMPERATURE, PRESSURE, AND MAXIMUM TEST PRESSURE FOR RCPB COMPONENTS (Continued)

Component	Design Temperature (F)	Design Pressure (psig)	Maximum Test Pressure (psig)
System block valve to and including second check valve (F007)			
Piping	150	1700	(1)
Valves	150	1700	(2)
Second check valve to and including third check valve (F006)			
Piping	150	1700	(1)
Valves	150	1700	(2)
Reactor Water Cleanup System			
Pump Suction			
Recirculation Piping to Isolation Valve Outside Drywell			
Piping	575	1250	(1)
Valves	575	1250	(2)
Beyond isolation valve			
Piping	575	1250	(1)
Pump and valves	575	1250	(2)

TABLE 5.2-3: DESIGN TEMPERATURE, PRESSURE, AND MAXIMUM TEST PRESSURE FOR RCPB COMPONENTS (Continued)

Component	Design Temperature (F)	Design Pressure (psig)	Maximum Test Pressure (psig)
Pump discharge to feedwater inlet			
Piping	575	1410	(1)
Pumps and valves	575	1410	(2)
Exchangers and vessels	575	1410	(2)

(1) Test pressure is calculated at 1.25 x design pressure x lowest stress intensity ratio.

(2) Test pressure is calculated at 1.50 x design pressure x lowest stress intensity ratio.

(3) Test pressure as defined by ASME Code Section III based on design pressure designated.

TABLE 5.2-4: REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

Component	Form	Material	Specification (ASTM/ASME)
Reactor Vessel Heads, Shells	Rolled Plate or Forgings	Low Alloy Steel	SA533 Gr.B Class 1 or SA 508 Cl. 2
	Welds	Low Alloy Steel	SFA 5.5
Closure Flange	Forged Ring	Low Alloy Steel	SA 508 Cl. 2
	Welds	Low Alloy Steel	SFA 5.5
Nozzles	Forged Shapes	Low Alloy Steel	SA 508 Cl. 2
	Welds	Low Alloy Steel	SFA 5.5
Nozzle Safe Ends	Forgings or Plate	Stainless Steel	SA 182, F304, F316 or F316L SA 336, F8 or F8M SA 240, 304 or 316
	Welds	Stainless Steel	SFA 5.9 TP. 308L or 316L SFA 5.4 TP. 308L or 316L
Nozzle Safe Ends	Forgings	Ni-Cr-Fe	SB166 or SB167
	Welds	Ni-Cr-Fe	SFA 5.14 TP. ER Ni-CR-3 or SFA 5.11 TP. EN or FE-3
Nozzle Safe Ends	Forgings	Carbon Steel	SA 105 Gr. 2,SA 106 Gr. B or SA 508 Cl. 1

TABLE 5.2-4: REACTOR COOLANT PRESSURE BOUNDARY MATERIALS (Continued)

Component	Form	Material	Specification (ASTM/ASME)
	Welds	Carbon Steel	SFA 5.1, SFA 5.18 GPA, or SFA 5.17 F70.
Cladding	Weld Overlay	Austenitic Stainless Steel	N/A
Control Rod	Pipe	Austenitic	SA 312 TP 304 or TP 304L
Drive Housings	Forging Tube Welds	Stainless Steel Inconel 600 Inconel	SA-182, F304 SB167 SFA 5.11, Type E Ni Cr Fe-3 or SFA 5.14, Type E R Ni Cr-3
In-Core	Tube	Ni-Cr-Fe	SB-167
Housings	Forging	Austenitic	SA-182, F304
	Welds	Ni-Cr-Fe	SFA 5.14, Type E R NiCr-3
Main Steam Piping - ASME Code, Class 1			
Elbow	Fitting	Carbon Steel	SA-420, Gr. WPBW, Code Case 1571
Pipe	Seamless	Carbon Steel	SA-155, Gr. KCF70, Cl. 1
	Plate		A516, Gr. 70
Pipe	Seamless	Carbon Steel	SA-106, Gr. B

TABLE 5.2-4: REACTOR COOLANT PRESSURE BOUNDARY MATERIALS (Continued)

Component	Form	Material	Specification (ASTM/ASME)
Elbow	Fitting	Carbon Steel	SA-234 Gr. WPBW
	Plate	Carbon Steel	A516 Gr. 70 Code Case 1571
Flange	Forging	Carbon Steel	SA-105
Nozzles	Forging	Carbon Steel	SA-105, Code Case 1519
	Forging	Carbon Steel	SA-181, Gr. II
Lugs	Plate	Carbon Steel	SA-516, Gr. 70
Nozzles	Forging	Carbon Steel	SA-350, Gr. LF2
Safe End	Forging	Carbon Steel	SA-508, Cl. 1
Safety/Relief Valve Piping - ASME Code, Class 3			
Pipe	Seamless	Carbon Steel	SA-106, Gr. B
Ball Joint	Fitting	Carbon Steel	SA-234, Gr. WPB or Gr. WPC
Elbow	Fitting	Carbon Steel	SA-234, Gr. WPB or Gr. WPC
Flange	Forging	Carbon Steel	SA-105
Nozzle	Forging	Carbon Steel	SA-105, Code Case 1519
	Forging	Carbon Steel	SA-181, Gr. II

TABLE 5.2-4: REACTOR COOLANT PRESSURE BOUNDARY MATERIALS (Continued)

Component	Form	Material	Specification (ASTM/ASME)
Bolt	Bolting	Low Alloy	SA-193, Gr. B7
Nut	Bolting	Low Alloy	SA 194, Gr. 2H
Recirculation Piping - ASME Code, Class 1			
Pipe	Welded	Stainless	SA 358, Gr. 304,Cl. I
Pipe	Seamless	Stainless	SA-376, TP 304
Elbow	Fitting	Stainless	SA-403, Gr. WP304W or
	Plate	Stainless	SA-240, Gr. WP304LW
Nozzle	Fitting	Stainless	SA-403, Gr. WP304
	Plate	Stainless	SA-240
Flange	Forging	Stainless	SA-182, Gr. F316
Lug	Plate	Stainless	SA-240, Gr. 304
Bolt	Bolting	Low Alloy	SA-193, Gr. B7
Nut	Bolting	Low Alloy	SA-194, Gr. 7, 2H
Safe End	Forging	Stainless	SA-182, Gr. 316L

Additional RCPB component materials and specifications to be used are specified below.

TABLE 5.2-4: REACTOR COOLANT PRESSURE BOUNDARY MATERIALS (CONTINUED)

Depending on whether impact tests are required and depending on the lowest service metal temperature when impact tests are required, the following ferritic materials and specifications are used:

Pipe	SA-106 Grade B and C; and SA-155 Grade KCF
Valves	SA-105 Grade II; SA-350 Grade LF1 or LF2 and SA-216 Grade WCB and WCC; SA-352 Grade LCB
Fittings	SA-105; SA-181 Grade II; SA-350 Grade LF1 or LF2; SA-234 Grade WPBW, WPCW, and WPC; SA-240 Grade WPBW
Bolting	SA-193 Grade B7 and B16 SA-194 Grades 7 and 2H
Welding Material	SFA-5.1 (E-7015, E-7016, E-7018) SFA-5.5 (E-7010A1, E-7015, E-7016, E-7018) SFA-5.17, SFA-5.18 (E70S-2)

For those systems or portions of systems, such as the reactor recirculation system, which require austenitic stainless steel, the following materials and specifications are used.

Pipe	SA-376 Type 304; SA-312 Type 304 and 304L; SA-358 Type 304
Valves	SA-182 Grade F-304, 304L, 316, 316L; SA-351 Grades CF3, CF3A, CF-8, CF-8M, and CF-3M
Pump	SA-182 Grade F-304; SA-351 Grades CF-8 and CF-8M
Flanges	SA-182 Grade F-316, F-304
Bolting	SA-193 Grade B7 and B16; SA-194 Grades 7 and 2H
Welding Material	SFA-5.4 (E308-15, E308L-15, E316-15); SFA-5.9 (ER-308, ER-308L, ER-316)
Fittings	SA-182 Grade F-304 and 304L; SA-403 Grades WP-304, 304L, 304W and 304LW

______

NOTE: In some instances, alternate materials may be used provided the substitute material has equivalent or higher stress allowables and the ferrite content of all stainless steel materials is strictly maintained.

TABLE 5.2-5: RCPB PUMP & VALVE DESCRIPTION

Location	Active/ Inactive	Valve No.	Isolation Mode	Maximum Closure Time
RHR (LPCI)	Active	E12F041	AO check	Instantaneous
	Active	E12F042	Remote manual	N/A
	Inactive	E12F039	Local manual	N/A
RHR Shutdown Cooling-Suction	Active	E12F009	IVCS	40 sec
	Active	E12F008	IVCS	40 sec
	Inactive	E12F010	Local manual	N/A
	Active	E12F308	Stop check	Instantaneous
MSIV	Active	B21F022/028	IVCS	5 sec
Main Steam S/R Valve	Active	B21F041/047/051	AO	Remote manual*
Feedwater In	Active	B21F010	Simple check	Instantaneous
	Active	B21F032	AO check	Instantaneous
	Inactive	B21F011	Local manual	N/A
Main Steam Drain Inboard	Active	B21F016	IVCS	**
	Active	B21F019	IVCS	**
	Inactive	B21F121	Local manual	N/A

*Safety/relief valves must be fully open within 0.25 second to perform safety-related functions (power mode).

TABLE 5.2-5: RCPB PUMP & VALVE DESCRIPTION (Continued)

Location	Active/ Inactive	Valve No.	Isolation Mode	Maximum Closure Time
Main Steam Drain Outboard	Active	B21F067	IVCS	**
Vessel Head Vent	Inactive	B21F001	Remote manual	N/A
	Inactive	B21F002	Remote manual	N/A
	Inactive	B21F005	Remote manual	N/A
RCIC Steam Supply	Active	E51F063	IVCS	60 sec
	Active	E51F076	IVCS	60 sec
	Active	E51F064	IVCS	60 sec
HPCS In	Active	E22F005	AO check	Instantaneous
	Active	E22F004	Remote manual	N/A
	Active	E22F036	Local manual	N/A
LPCS In	Active	E21F006	AO check	Instantaneous
	Active	E21F005	Remote manual	N/A
	Inactive	E21F007	Local manual	N/A
Standby Liquid Control In	Active	C41F007	Stop check	Instantaneous
	Active	C41F006	Stop check	Instantaneous
	Active	C41F222	Stop check	Instantaneous
	Inactive	C41F008	Local manual	N/A

TABLE 5.2-5: RCPB PUMP & VALVE DESCRIPTION (Continued)

Location	Active/ Inactive	Valve No.	Isolation Mode	Maximum Closure Time
Reactor Water	Active	G33F001	IVCS	35 sec
Cleanup System	Active	G33F004	IVCS	35 sec
	Inactive	G33F103	Local manual	N/A
	Inactive	G33F100	Remote manual	N/A
	Inactive	G33F106	Remote manual	N/A
	Inactive	G33F102	Remote manual	N/A
	Inactive	G33F101	Remote manual	N/A
	Inactive	G33F120	Local manual	N/A
	Inactive	G33F421	Remote manual	N/A
Reactor Water	Active	G33F250	IVCS	35 sec
Cleanup System	Active	G33F251	IVCS	35 sec
	Active	G33F252	IVCS	35 sec
	Active	G33F253	IVCS	35 sec
Recirculation	Inactive	B33F023	Remote manual	N/A
Pump Suction	Inactive	B33F051	Local manual	N/A
	Inactive	B33F052	Local manual	N/A
Reactor Vessel Drain	Inactive	B33F029/F030	Local manual	N/A

TABLE 5.2-5: RCPB PUMP & VALVE DESCRIPTION (Continued)

Location	Active/ Inactive	Valve No.	Isolation Mode	Maximum Closure Time
Pump Discharge (Flow Control)	Inactive	B33F060	N/A	N/A
Pump Discharge	Inactive	B33F067	Remote manual	N/A
	Inactive	B33F059	Local manual	N/A
	Active	B33F019	IVCS	**
	Active	B33F020	IVCS	**
Pump Seal Injection	Active	B33F013	Stop check	Instantaneous
	Active	B33F017	Stop check	Instantaneous
	Inactive	B33F014	Local manual	N/A
Reactor Post-	Active	B33F125	Remote manual	N/A
Accident Sampling	Active	B33F126	Remote manual	N/A
MSIV Leakage Control	Active	E32F001	Remote manual(***)	N/A
Feedwater Leakage Control	Active	E38F001	Remote manual	N/A
	Active	E38F002	Stop check	Instantaneous

** See SEP-GGNS-IST-1, GGNS Inservice Bases Document, for Inservice Testing Program maximum stroke time.

TABLE 5.2-5: RCPB PUMP & VALVE DESCRIPTION (CONTINUED)

<u>Pump Description</u>

Recirculation Pump Inactive

IVCS = Isolation Valve Control Signal

NOTE: Local manually operated 3/4-inch and 1-inch vent, drain, test connection isolation, and instrument root valves are not listed.

*** Valves auto isolate on High reactor pressure or main steam line pressure.

TABLE 5.2-6: TYPICAL BWR WATER CHEMISTRY FOR NORMAL OPERATION

	Concentrations-Parts Per Billion (ppb)				Conductivity	
	Iron	**Copper**	**Chloride**	**Oxygen**	**mho/cm @ 25 C**	**pH @ 25 C**
Condensate** (1)*	15-30	0.2	20	30-200	0.1	~7
Condensate Treatment Effluent (2)	1-5	0.2	0.2	30-200	0.1	~7
Feedwater (3)	1-5	0.2	0.2	30-200	0.1	~7
Reactor Water (4)						
(a) Normal Operation (with Hydrogen water Chemistry)	1-20	0.5	1	0.1-2	0.06-0.2	~7
(b) Shutdown	-	-	2		1	~7
(c) Hot Standby	-	-	2	See Outline	1	~7
(d) Depressurized	-	-	2	8000	2	6-6.5

TABLE 5.2-6: TYPICAL BWR WATER CHEMISTRY FOR NORMAL OPERATION (CONTINUED)

	Concentrations-Parts Per Billion (ppb)				Conductivity	
	Iron	**Copper**	**Chloride**	**Oxygen**	**mho/cm @ 25 C**	**pH @ 25 C**
Steam (5)	0	0	0	10000-30000	0.1	-
Control Rod Drive Cooling Water (6)	1-5	-	1	50	0.1	~7

*Numerals in parentheses refer to locations delineated on Figure 5.2-14.

**Assume No Condenser Leaks

TABLE 5.2-6: TYPICAL BWR WATER CHEMISTRY FOR NORMAL OPERATION (CONTINUED)

Coolant Chemistry Requirements

Coolant Chemistry Limiting Condition for Operation	**Coolant Chemistry Surveillance Requirements**
a. Prior to startup and during reactor operation when the reactor is pressurized, or above 212 F, and at less than 1 percent of rated steam flow, including hot standby the reactor coolant shall not exceed the following limits: Conductivity at 25 C 2 µmho/cm Chloride 0.1 ppm	a. Reactor coolant shall be continuously monitored to conductivity. 1. Whenever the continuous conductivity monitor is inoperable, an in-line conductivity measurement shall be obtained at least once every four hours. 2. Once a week the continuous monitor shall be checked with in an in-line flow cell. This in-line conductivity calibration shall be performed every 24 hours whenever the reactor coolant conductivity is 1.0 µmho/cm at 25 C.
b. During reactor operation in excess of 1 percent of rated steam flow, the reactor coolant shall not exceed the following limits: Conductivity at 25 C 1 µmho/cm Chloride 0.2 ppm	b. During startup prior to pressurizing the reactor above atmospheric pressure, measurements of reactor water quality shall be performed to show conformance with Paragraph a of limiting conditions.

TABLE 5.2-6: TYPICAL BWR WATER CHEMISTRY FOR NORMAL OPERATION (CONTINUED)

During reactor operation in excess of 1 percent of rated steam flow, the reactor coolant may exceed the limits of Paragraph b only for the time limits specified here. Exceeding these time limits or the following maximum limits shall be cause for immediately shutting down and placing the reactor in the cold shutdown condition. Conductivity: Time above 1 µmho/cm at 25C 2 weeks/year Maximum limit- 10 µmho/cm at 25C Chloride: Time above 0.2 ppm 2 weeks/year Maximum limit - 0.5 ppm The reactor shall be shutdown if the pH is 5.6 or 8.6 for a 24-hour period.	c. Whenever the reactor is operating (including hot standby conditions), measurements of reactor water quality shall be performed according to the following schedule: 1. Chloride ion content shall be measured at least once every 96 hours. 2. Chloride ion content shall be measured at least every eight hours whenever reactor conductivity is >1.0 µmho/cm at 25 C. 3. Primary coolant pH shall be measured at least once every eight hours whenever the reactor coolant conductivity is >1.0 µmho/cm at 25 C.
d. When reactor is not pressurized (i.e., at or below 212 F), reactor coolant shall be maintained below the following limits: Chloride at 25 C10 µmho/cm 0.5 ppm and pH shall be between 5.3 and 8.6.	d. Whenever the reactor is not pressurized, a sample of the reactor coolant shall be analyzed at least every 96 hours for chloride ion content an pH.
e. When the time limits or maximum conductivity or chloride concentration limits are exceeded, an orderly shutdown shall be initiated immediately. The reactor shall be brought to the cold shutdown condition as rapidly as cooldown rate permits.	

TABLE 5.2-7: SYSTEMS WHICH MAY INITIATE DURING OVERPRESSURE EVENT

System	Initiating/Trip Signal(s)
Reactor Protection System	Reactor trips "OFF" on High Flux
RCIC	"ON" when Reactor Water Level <L2 "OFF" when Reactor Water Level >L8
HPCS	"ON" when Reactor Water Level <L2 "OFF" when Reactor Water Level >L8
Recirculation System	"OFF" when Reactor Water Level <L2 "OFF" when Reactor Pressure >1095 psig
RWCU	"OFF" when Reactor Water Level <L2

TABLE 5.2-8: WATER SAMPLE LOCATIONS

Sample Origin	Sensor Location	Indicator Location	Recorder Location	Range µmho	High	Minimum Accuracy(b)
Reactor Water Recirculation Loop	Sample Line	Sample Station	Control Room	0-0.5	0.2(a)	±1%
Reactor Water Cleanup System Inlet	Sample Line	Sample Station	Control Room	0-0.5	0.2(a)	±1%
Reactor Water Cleanup System Outlets	Sample Line	Sample Station	Control Room	0-0.5	0.1	±1%
Stored Condensate Control Rod Drive System	Sample Line	Sample Station	Control Room	0-0.5	0.1	±1%

(a) This value is used to provide annunciation before the recommended limit of 0.3 µmho is exceeded. (BWRVIP-130: BWR Vessel and Internals Project BWR Water Chemistry Guidelines 2004 Revision).

(b) The accuracy is expressed as percent of full scale range. The instruments are sensitive to within or less than the accuracy, and are periodically (1/week) calibrated against laboratory calibration instruments.

TABLE 5.2-9: SUMMARY OF ISOLATION/ALARM OF SYSTEM MONITORED AND THE LEAK DETECTION METHODS USED

FUNCTION		**A**	**A**	**A**	**A**	**A/I**	**A/I**	**A/I**	**A/I**	**A/I**	**A**	**A**	**A**
Variable Monitored→ Source of Leakage (2)↓	Location	D Sump High Flow Rate	Fission Products High Radiation	High/D Air Cooler Condensate Rate	High D Temperature	Equipment Area High T&ΔT (5)	High Flow Rate (1)	RWCU Δ Flow (high)	Low Steamline Pressure	Reactor Low Water (3)	OD Sump or Drain High Flow Rate	High Δ Pressure (6)	High D Pressure (3)
Main Steamline	D --- OD	X -----	X ---	X ---	X ---	 --- X	X --- X	---	---	X --- X	 --- X	---	X ---
RHR	D --- OD	X -----	X ---	X ---	X ---	 --- X	X --- X	---	---	X --- X	 --- X	---	X ---
RCIC Steam	D --- OD	X -----	X ---	X ---	X ---	 --- X	X --- X	---	X ---	---	 --- X	---	X ---
RCIC Water	D --- OD	X -----	---	---	---	---	---	---	---	---	 --- X	---	X ---
Reactor Water Cleanup	D --- OD --- OD	X ----- hot ----- cold	X --- ---	X --- ---	X --- ---	 --- X ---	 --- ---	X --- X --- X	 --- ---	X --- X --- X	 --- X --- X	 --- ---	X --- ---
Feedwater	D --- OD	X -----	X ---	X ---	X ---	 --- X[4]	---	---	---	---	 --- X	---	X ---
Upper Containment Pool	D --- OD	X -----	---	---	---	---	---	---	---	---	 --- X	---	---
ECCS Water	D --- OD	X -----	X ---	---	---	---	---	---	---	---	 --- X	X ---	X ---

D - Drywell
OD - Outside Drywell
RWCU - Reactor Water Cleanup
A - Alarm
I - Isolation

NOTES:

1. Break downstream of flow element will isolace the system.
2. All systems within the drywell share a common detect ion system.
3. Part of other safety systems.
4. Alarm only (steam tunnel).
5. ΔT for alarm only.
6. The ECCS Line Break Instrumentation provides limited useful information. It is not capable of continuously confirming the integrity of the ECCS injection piping inside the reactor vessel as originally intended. The high and low differential pressure setpoints for the LPCS/RHR A Line break instrumentation have been changed so that it is unlikely that the alarms will actuate in the event of a pipe failure.

TABLE 5.2-10: Deleted

TABLE 5.2-11: RCPB OPERATING THERMAL CYCLES

	No. of Events
Normal, Upset and Testing - Conditions	
Bolt Up*	123
Design Hydrostatic Test	130
Startup (100 F/hr Heatup Rate)**	120
Daily Reduction to 75-Percent Power*	10,000
Weekly Reduction to 50-Percent Power*	2,000
Control Rod Pattern Change*	400
Loss of Feedwater Heaters (80 Cycles Total):	80
Scram:	
Turbine Generator Trip, Feedwater On, Isolation Valves Stay Open	40
Other Scrams	140
Bypass Loss of Feedwater Pumps, Isolation Valves Closed	10
Turbine Trip With Single Safety/Relief Valve Blowdown	8
Reduction to 0-Percent Power, Hot Standby, Shut-down (100 F/hr Cooldown Rate)**	111
Unbolt	123
Emergency Conditions	
Scram:	
Reactor Overpressure with Delay Scram, FeedwaterStays On, Isolation Valves Stay Open	1
Automatic Blowdown	1
Improper Start of Cold Recirculation Loop	1
Sudden Start of Pump in Cold Recirculation Loop	1
Hot Standby-Drain Shut off - Pump Restart	1

TABLE 5.2-11: RCPB OPERATING THERMAL CYCLES (Continued)

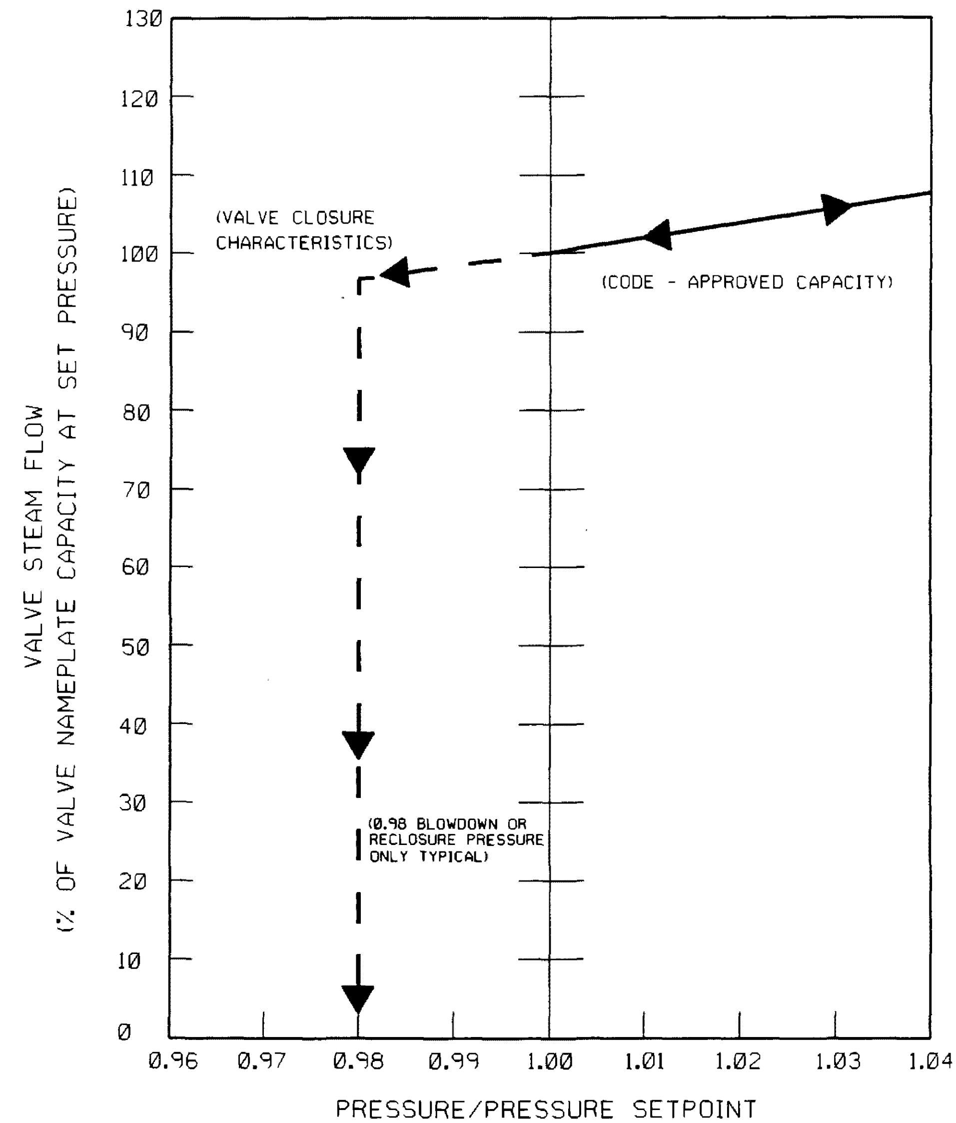
	No. of Events
Normal, Upset and Testing - Conditions	
Faulted Condition	
Pipe Rupture and Blowdown	1

* Applies to reactor pressure vessel only
** Bulk average vessel coolant temperature change in any one-hour

TABLE 5.2-12: DELETE

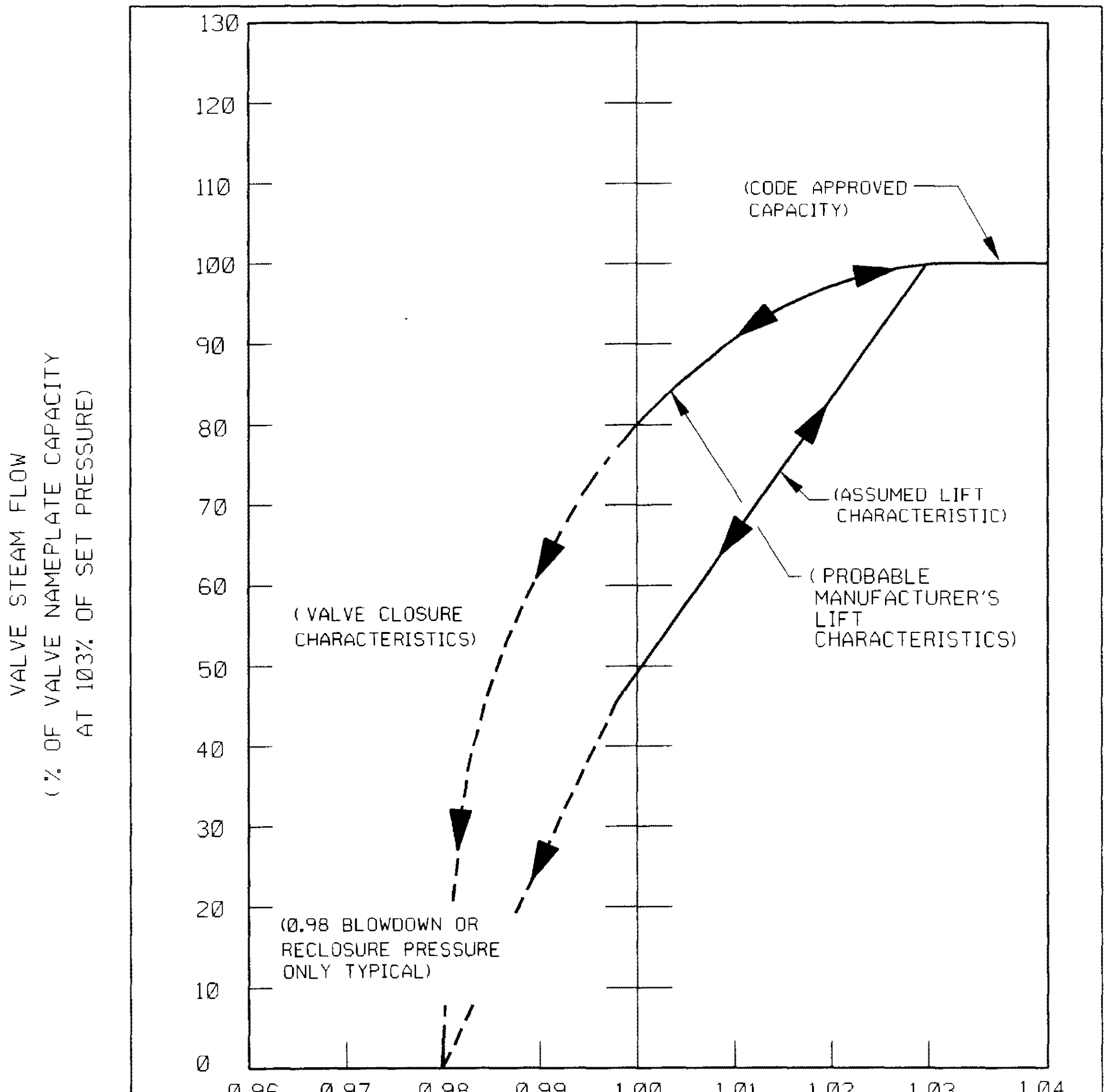
FIGURE 5.2-1: Deleted

Figures 5.2-1a through 5.2-1c Deleted



GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

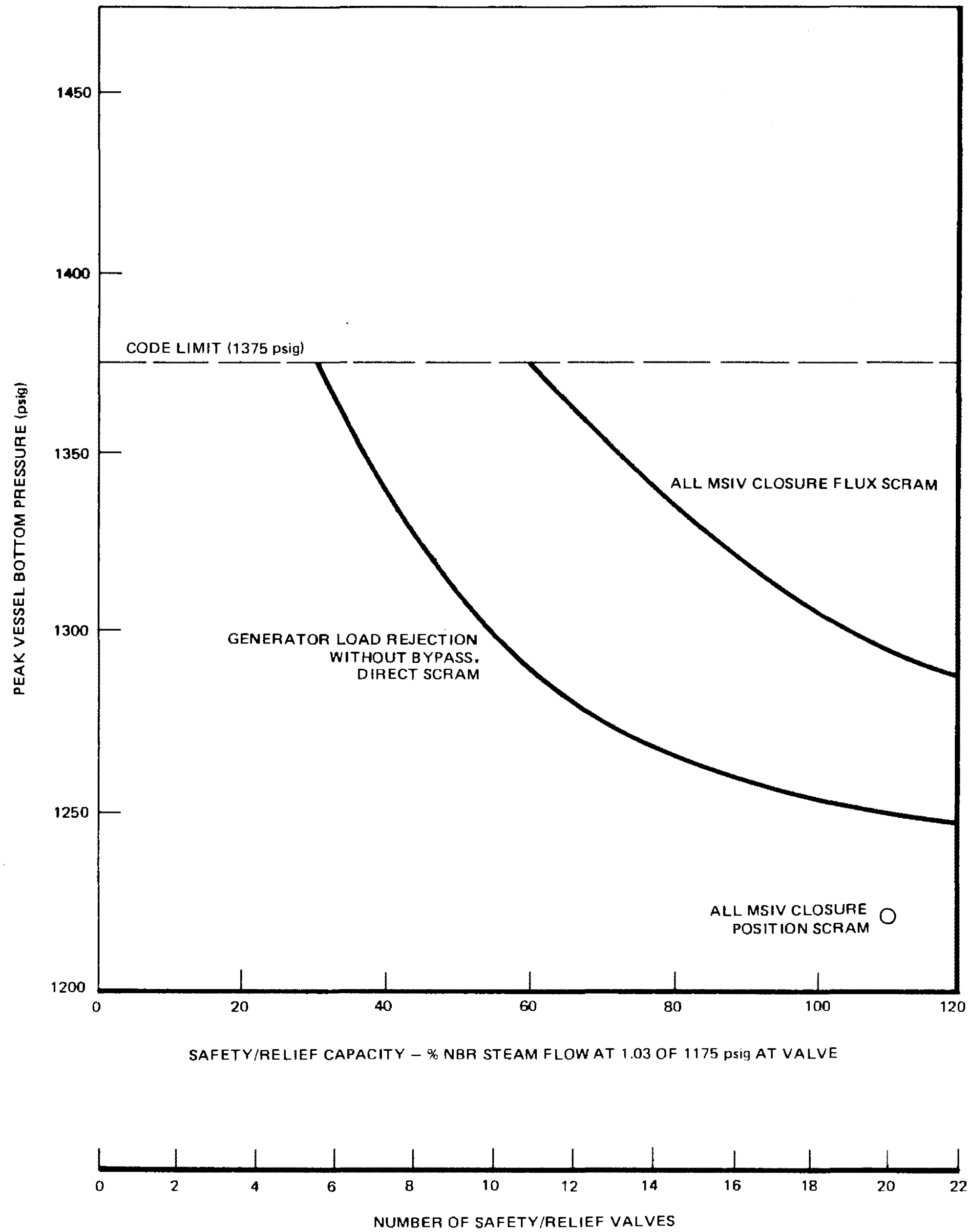
TYPICAL DUAL SAFETY/RELIEF VALVE
CAPACITY CHARACTERISTICS
POWER-ACTUATED RELIEF MODE
FIGURE 5.2-2
[HISTORICAL INFORMATION]



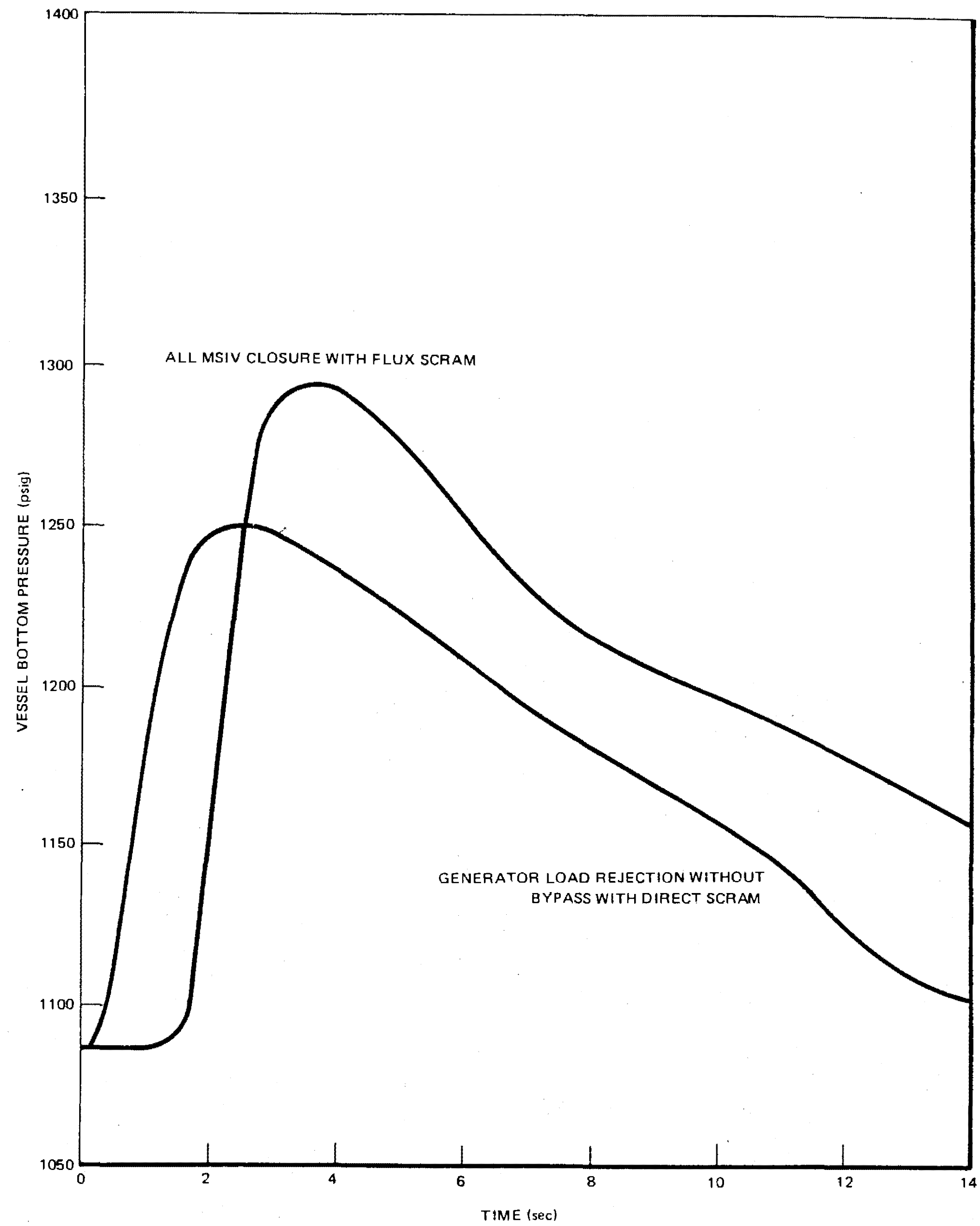
[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

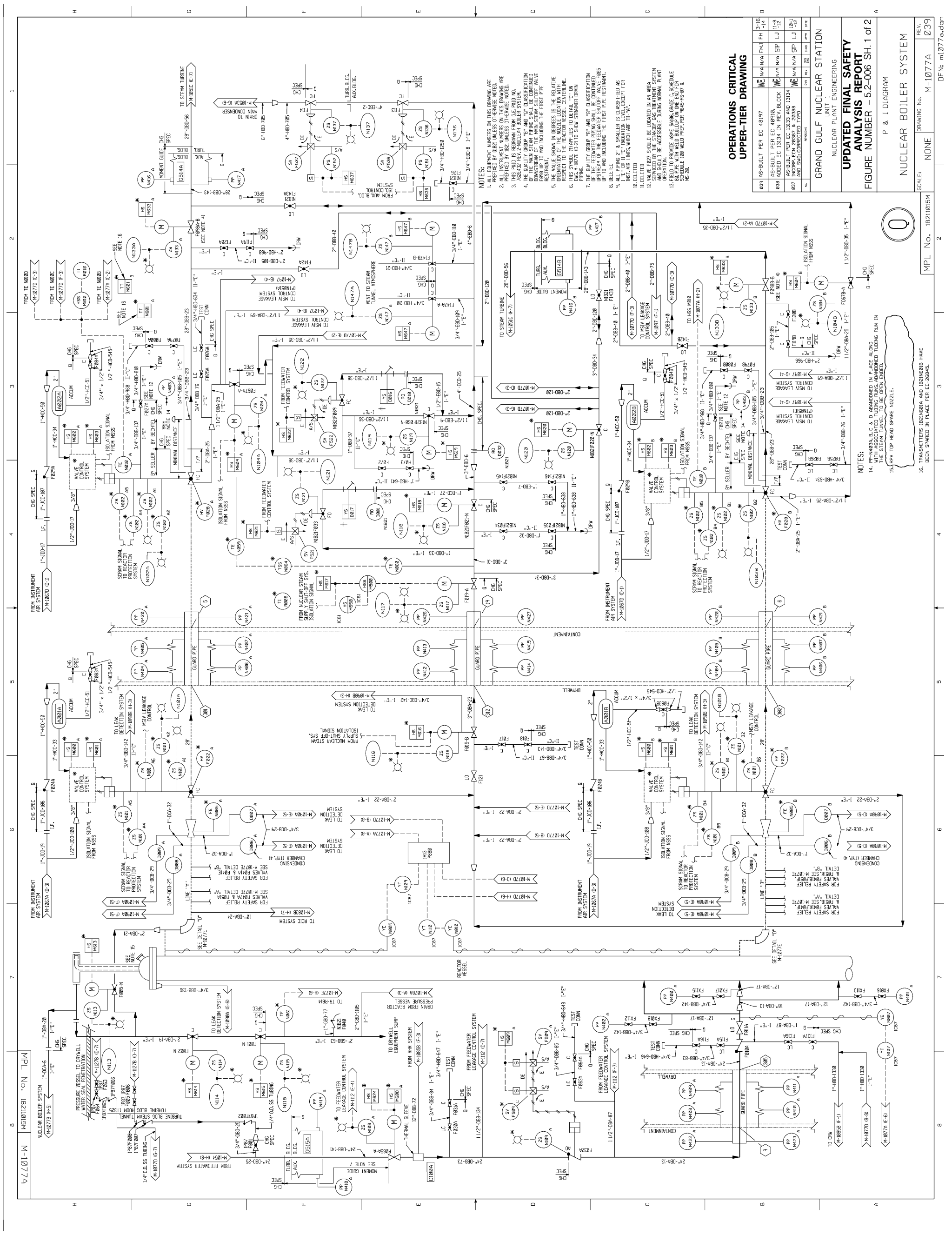
TYPICAL DUAL SAFETY/RELIEF VALVE
CAPACITY CHARACTERISTICS
SPRING - ACTION SAFETY MODE
FIGURE 5.2-3

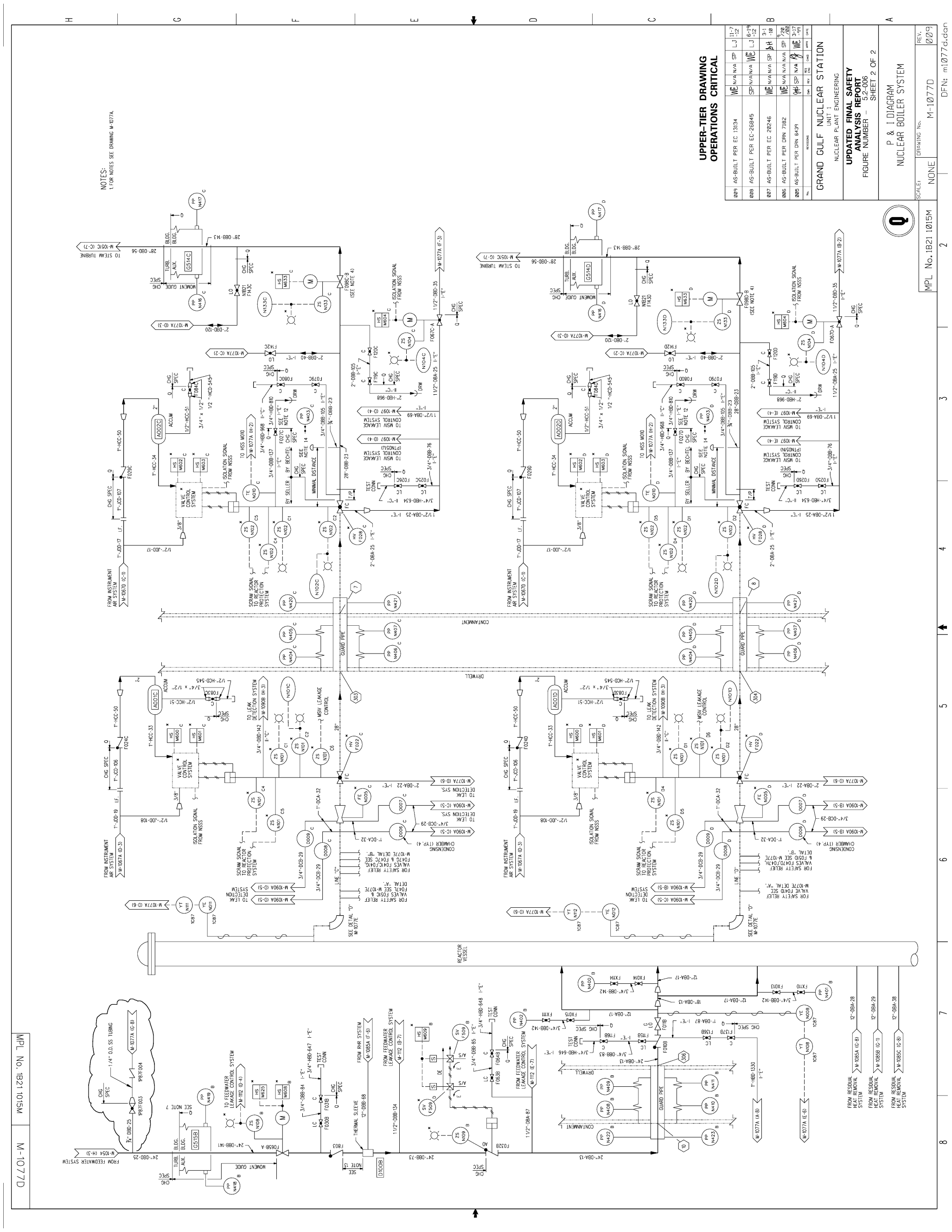


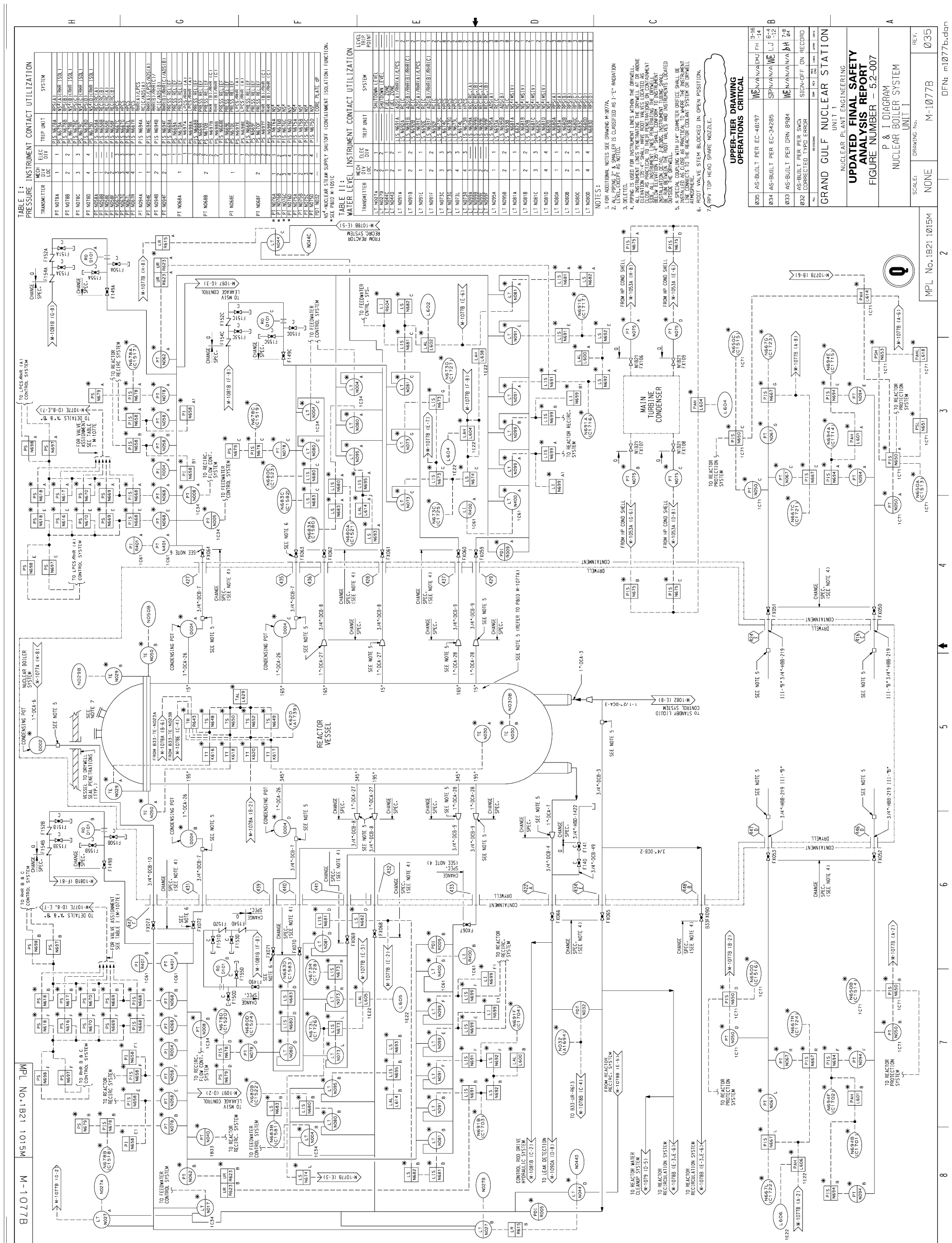
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PEAK VESSEL PRESSURE VERSUS SAFETY/RELIEF CAPACITY FIGURE 5.2-4

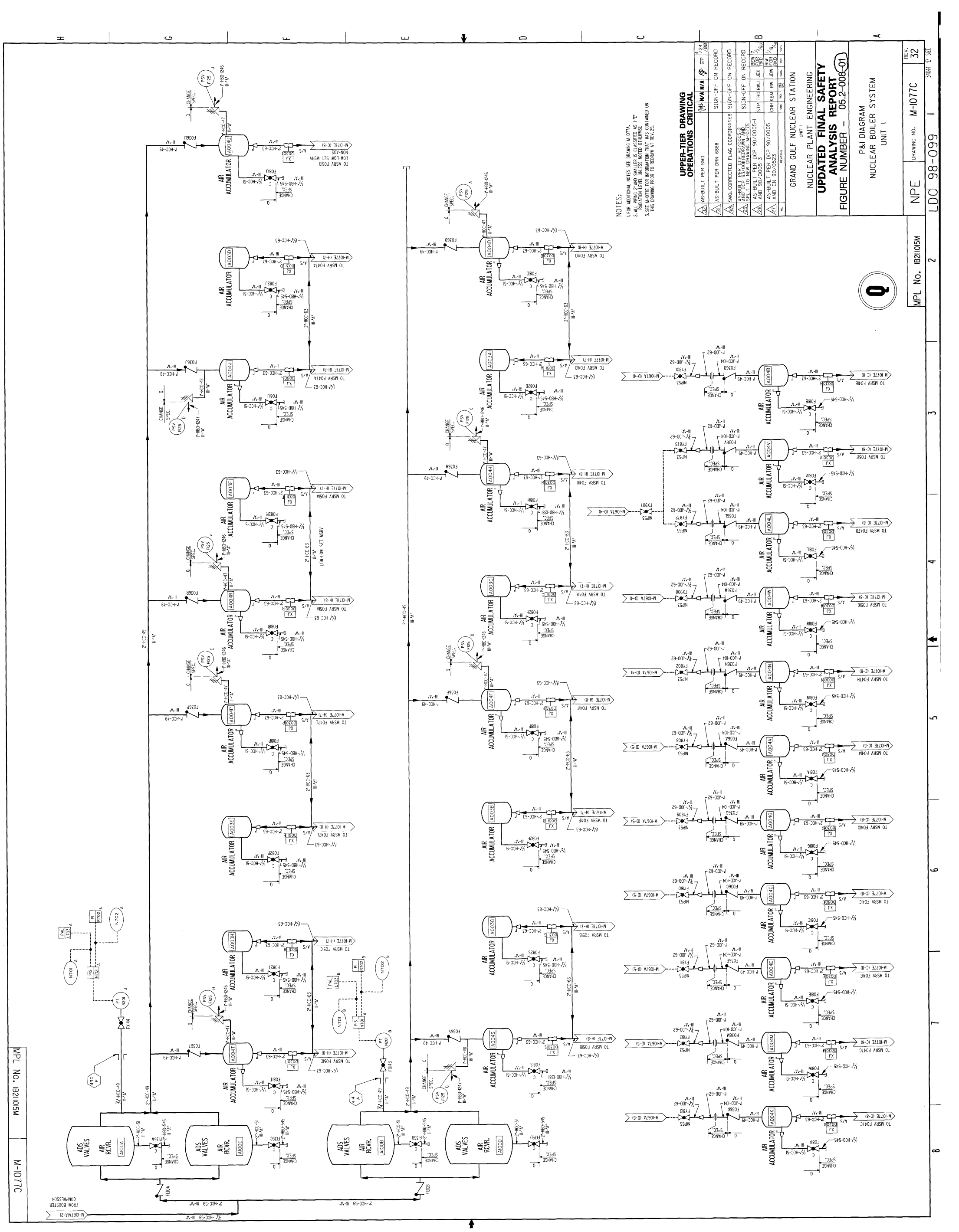


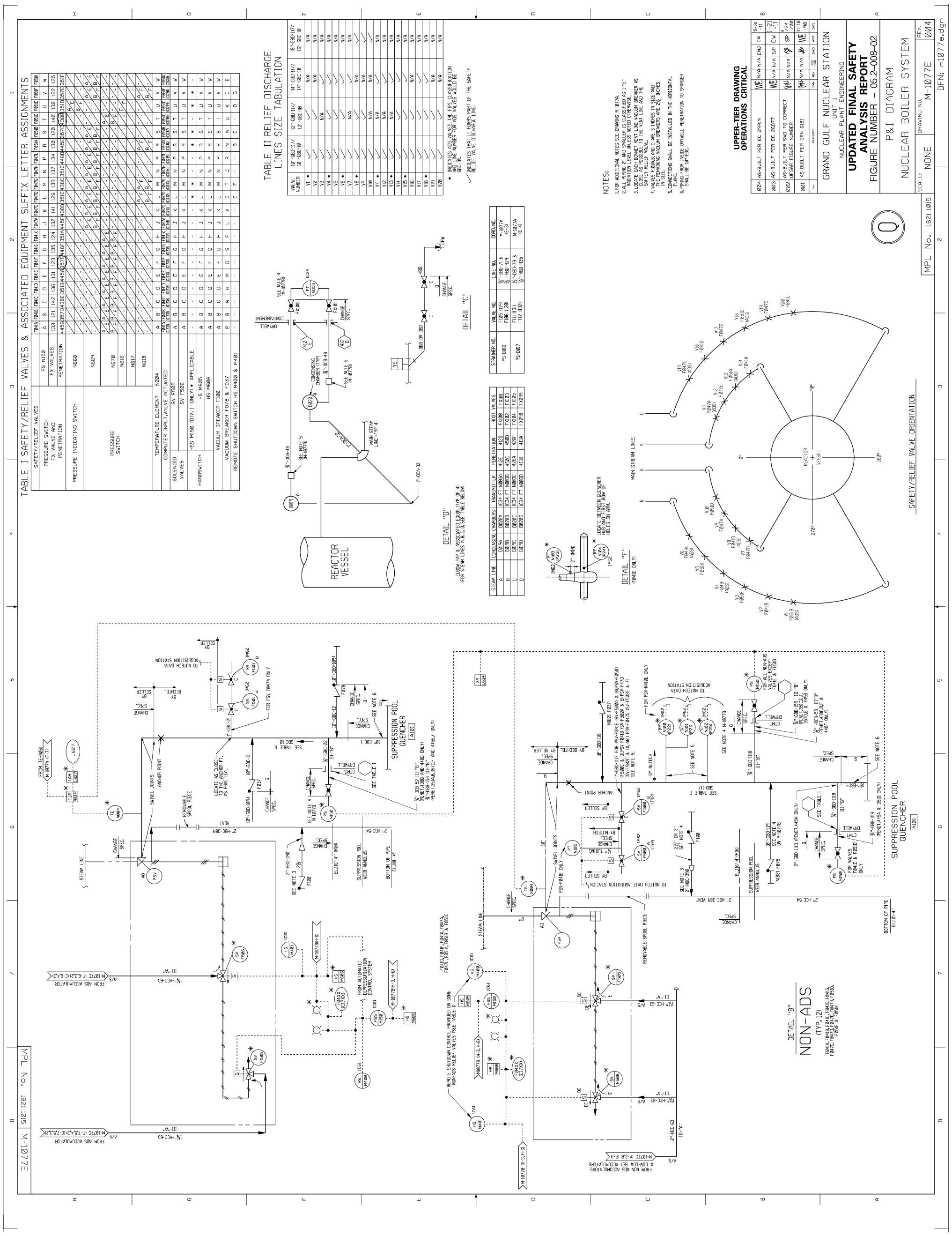
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PEAK VESSEL PRESSURE VERSUS TIME FOR SAFETY VALVE CAPACITY SIZING TRANSIENT FIGURE 5.2-5

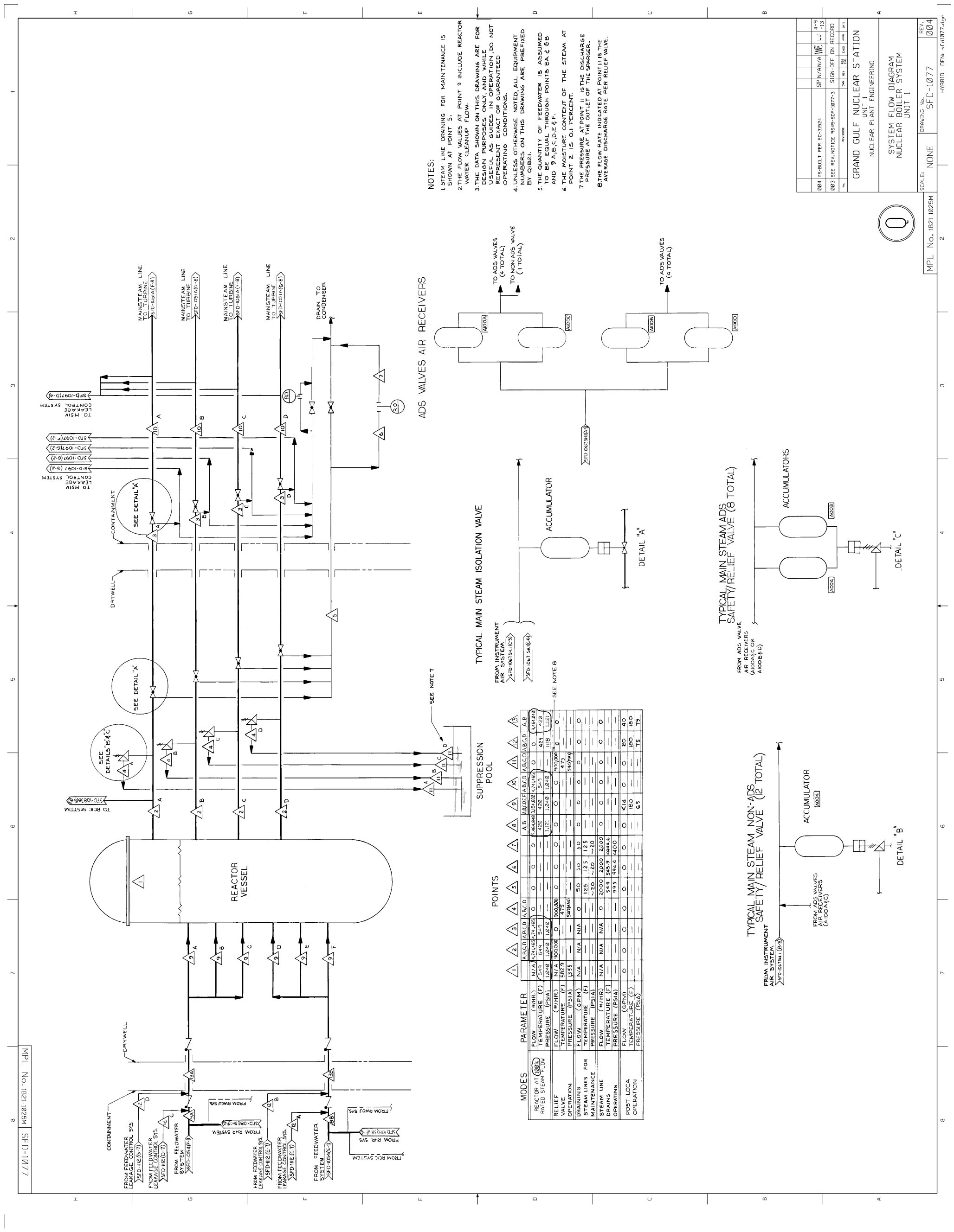


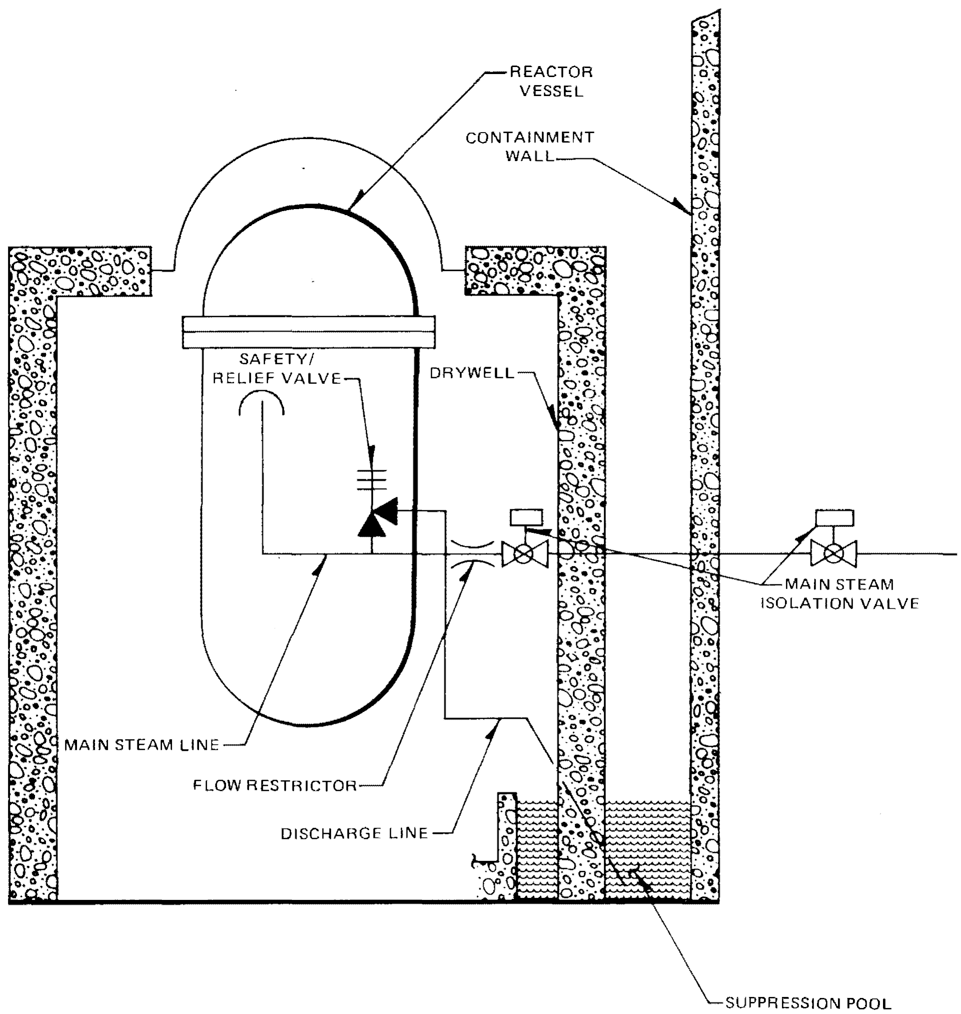

UPPER-TIER DRAWING
OPERATIONS CRITICAL
GRAND GULF NUCLEAR STATION
UPDATED FINAL SAFETY ANALYSIS REPORT
SHEET 2 OF 2
P & I DIAGRAM
NUCLEAR BOILER SYSTEM
M-1077D


GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER 5.2-007
P & I DIAGRAM
NUCLEAR BOILER SYSTEM
UNIT 1
M-1077B

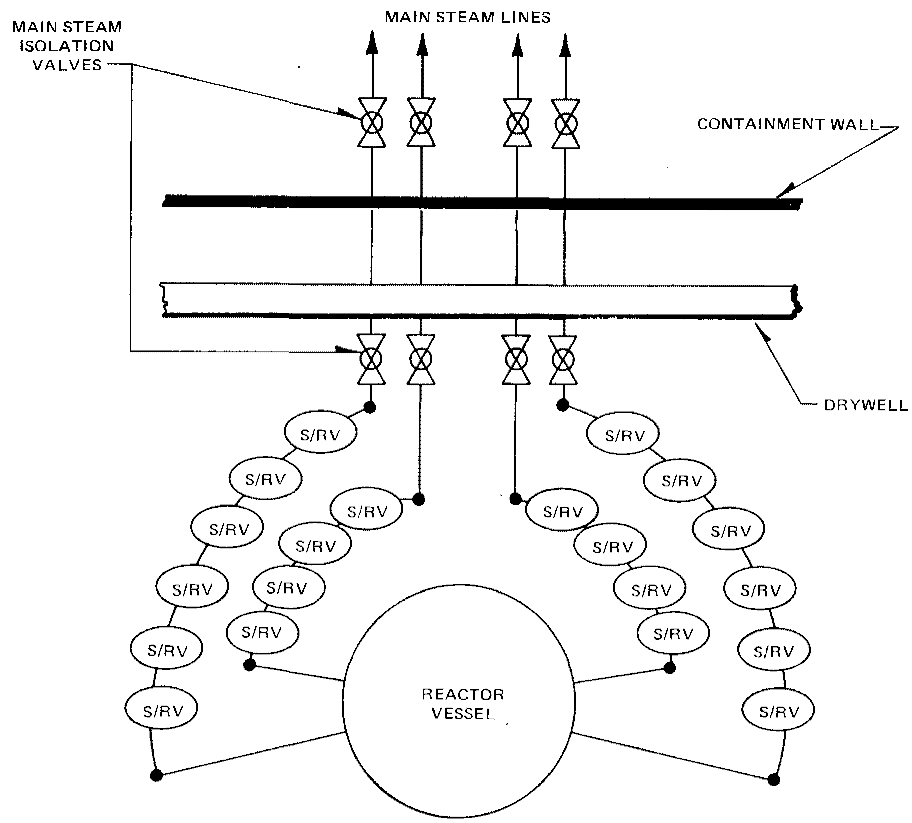

GRAND GULF NUCLEAR STATION
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER - 05.2-008-01
P&I DIAGRAM
NUCLEAR BOILER SYSTEM
UNIT 1
UPPER-TIER DRAWING OPERATIONS CRITICAL
M-1077C
LDC 98-099
NPE



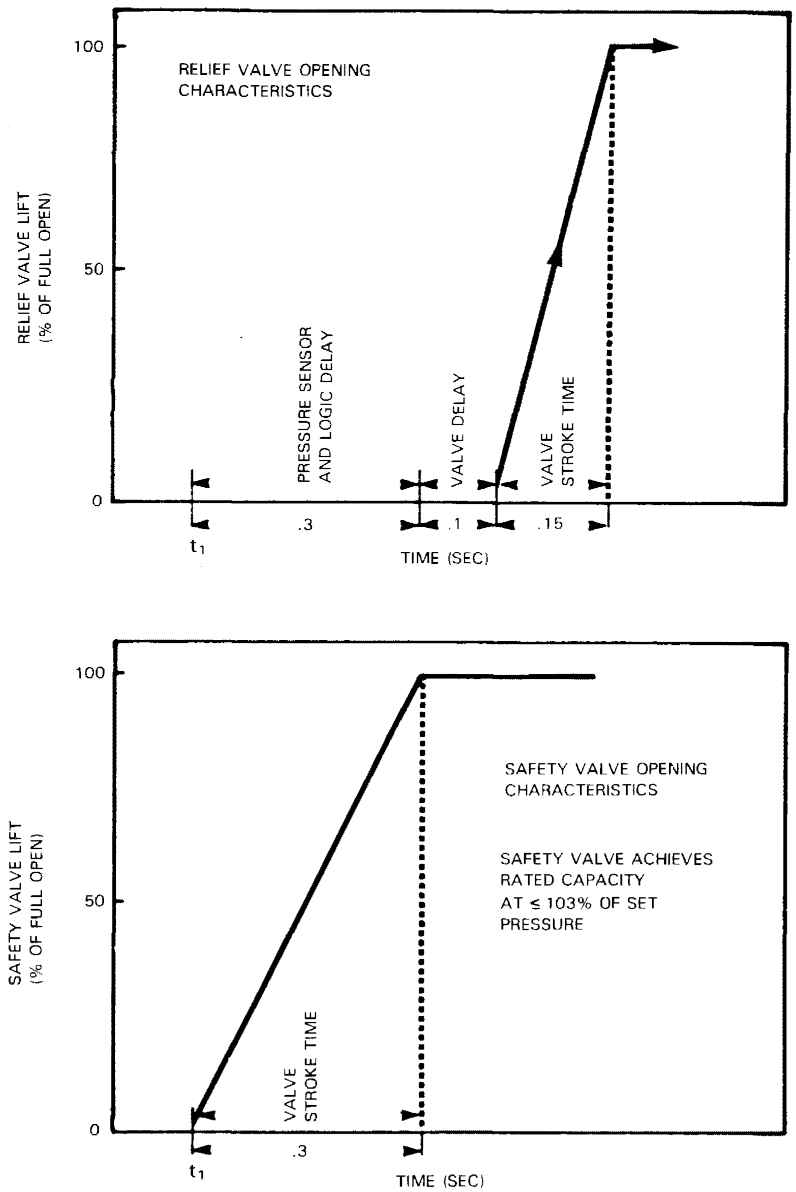

REACTOR VESSEL
SUPPRESSION POOL
ADS VALVES AIR RECEIVERS
TYPICAL MAIN STEAM ISOLATION VALVE
ACCUMULATOR
DETAIL "A"
DETAIL "B"
DETAIL "C"
ACCUMULATORS
POINTS
PARAMETER
MODES
NOTES:
GRAND GULF NUCLEAR STATION
SYSTEM FLOW DIAGRAM
NUCLEAR BOILER SYSTEM
UNIT 1
SFD-1077



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	SAFETY/RELIEF VALVE SCHEMATIC ELEVATION FIGURE 5.2-10

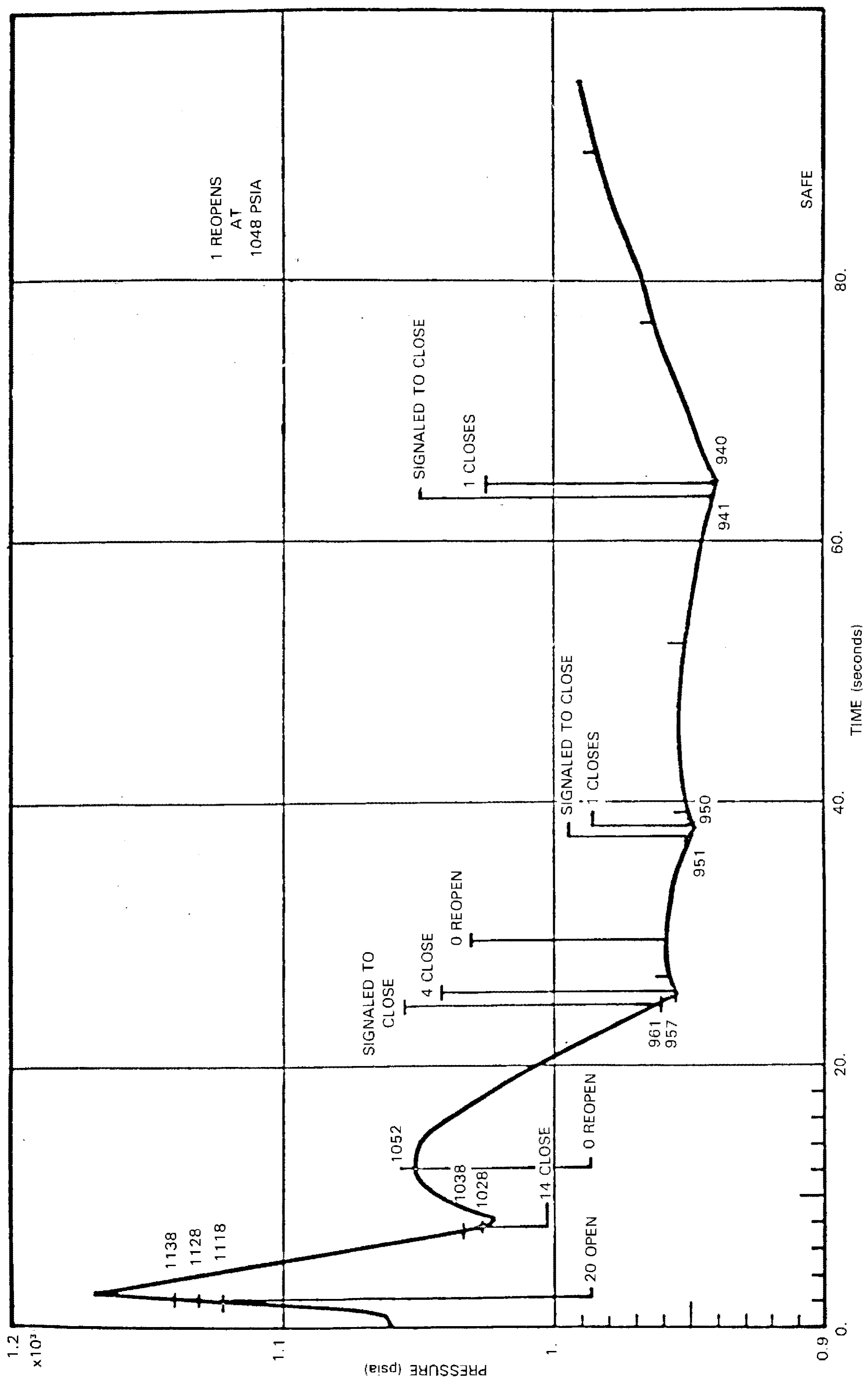


MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	SAFETY/RELIEF VALVE AND STEAM LINE SCHEMATIC FIGURE 5.2-11



t_1 = TIME AT WHICH PRESSURE EXCEEDS THE VALVE SET PRESSURE

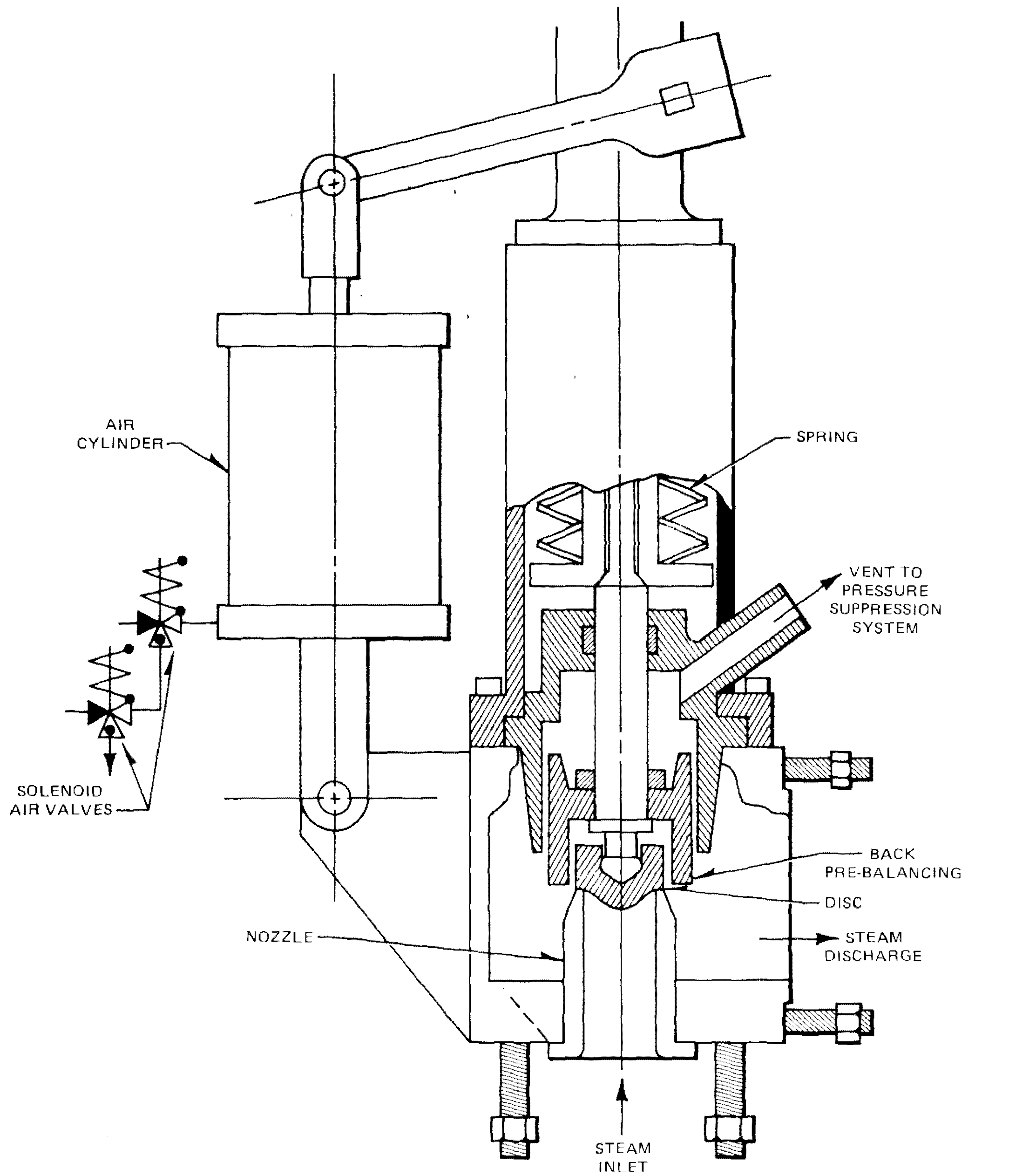
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	POWER ACTUATED AND SAFETY ACTION VALVE LIFT CHARACTERISTICS FIGURE 5.2-12



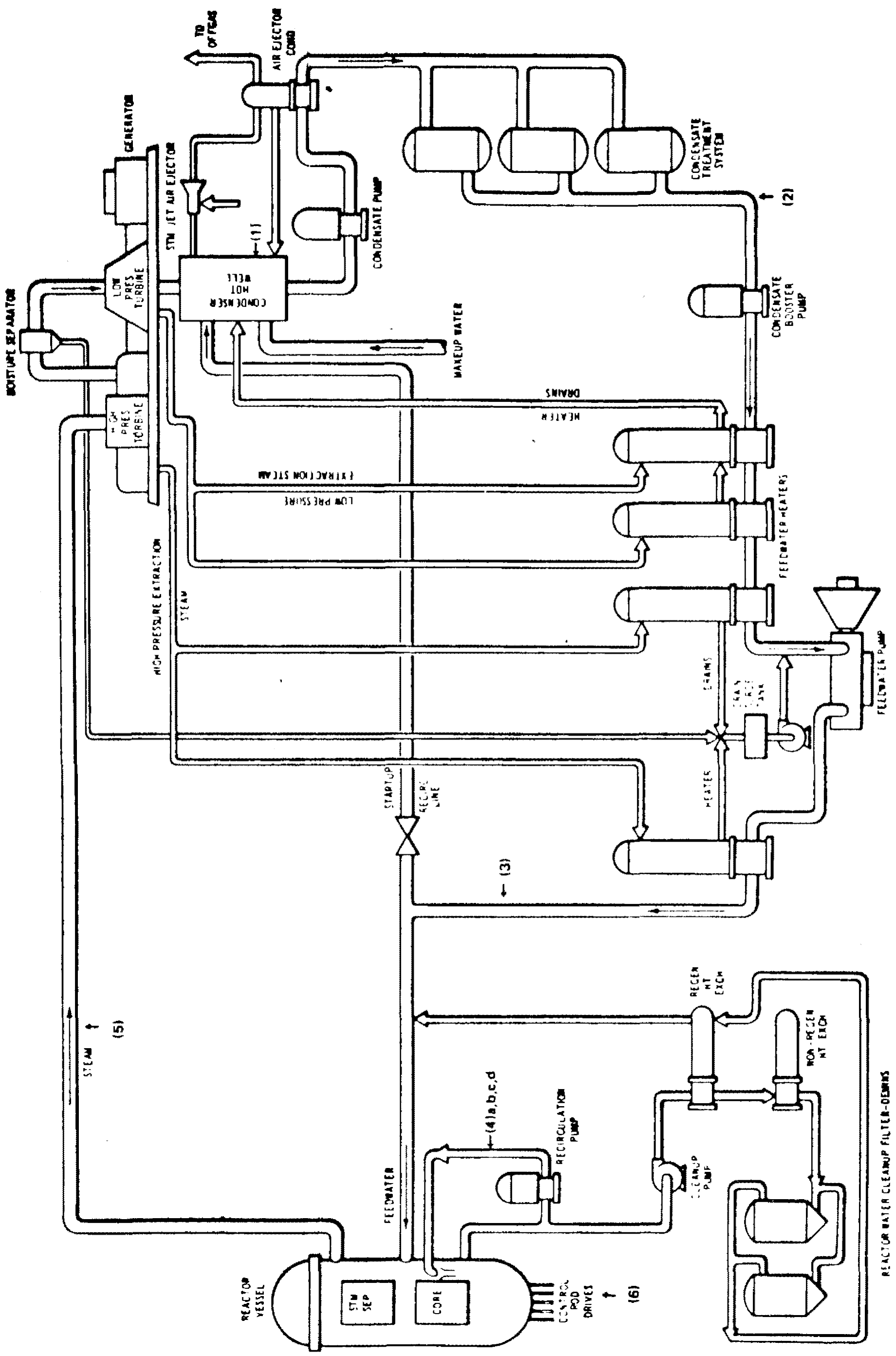
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL PRESSURE FOLLOWING
ISOLATION TRANSIENT

FIGURE 5.2-12a



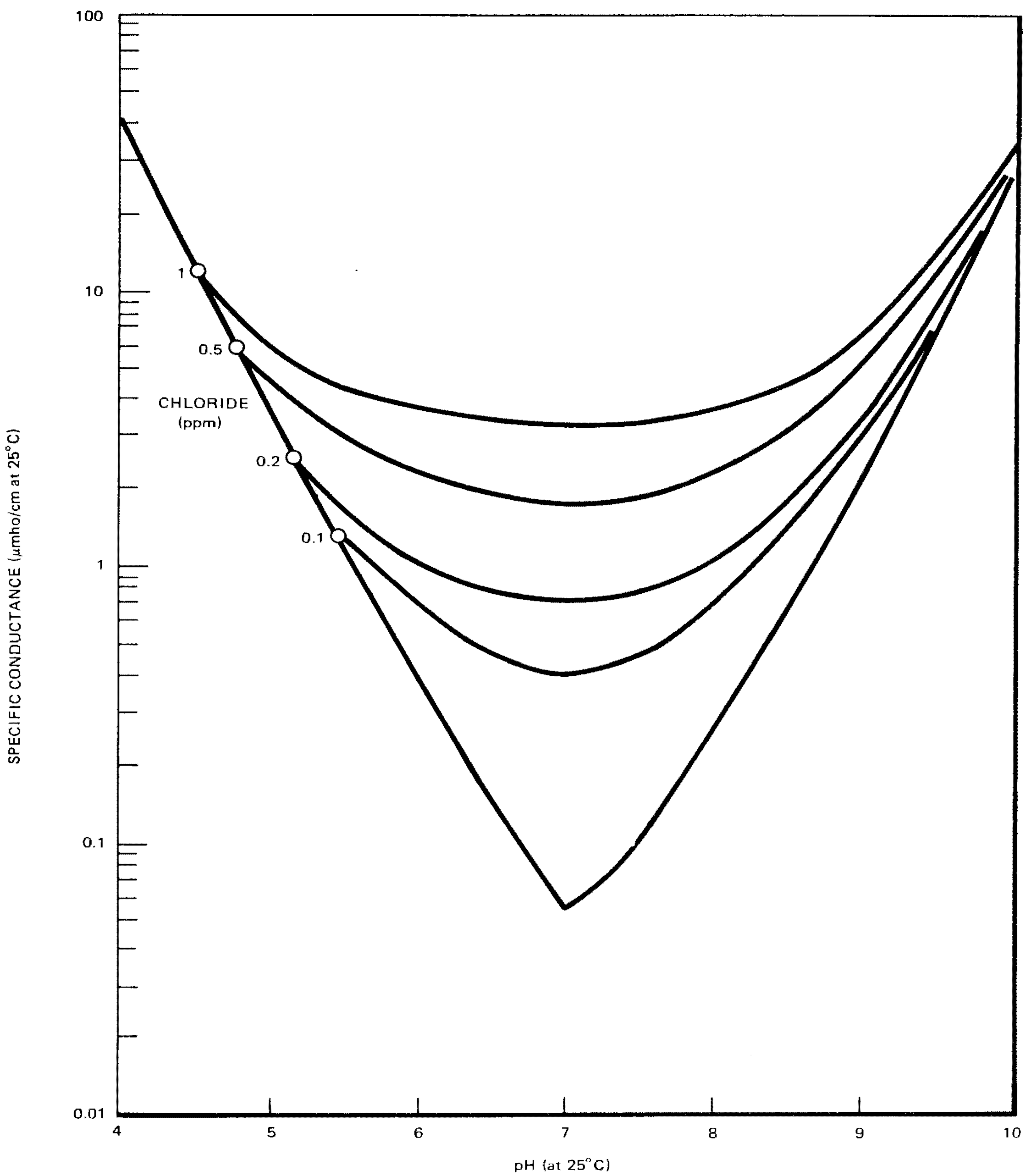
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	SCHEMATIC OF SAFETY VALVE WITH AUXILIARY ACTUATING DEVICE FIGURE 5.2-13



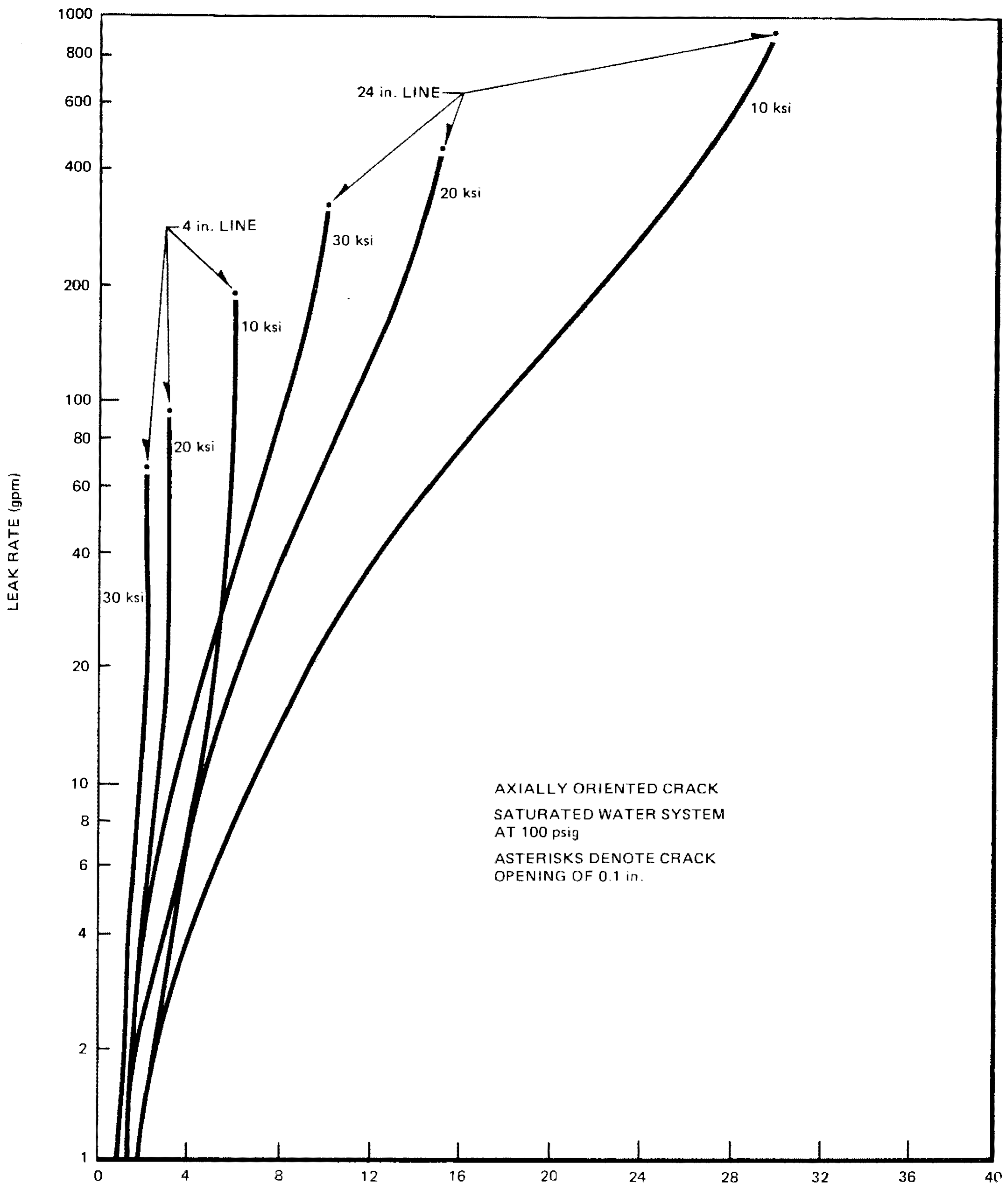
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL BWR FEEDWATER CYCLE

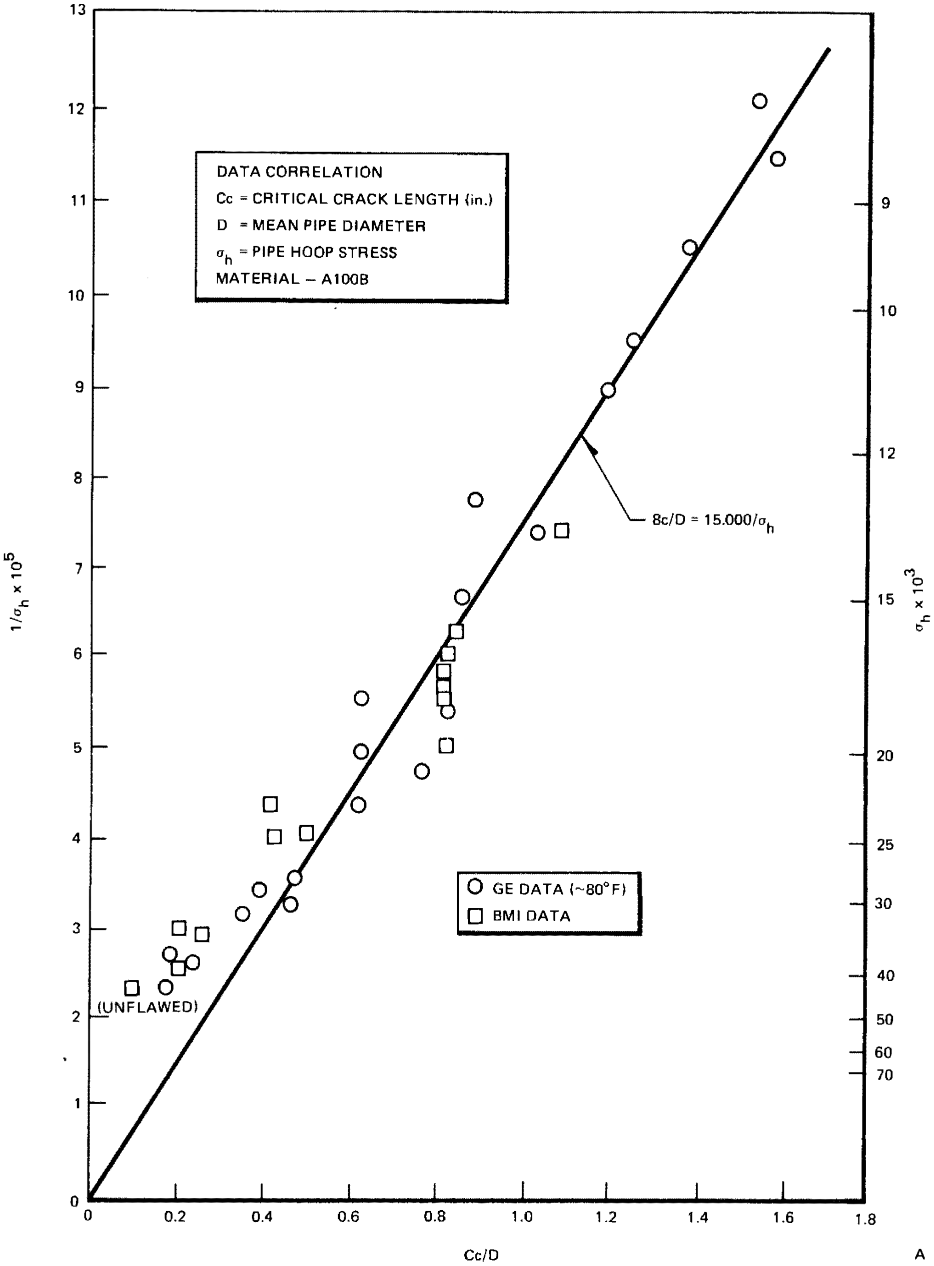
FIGURE 5.2-14



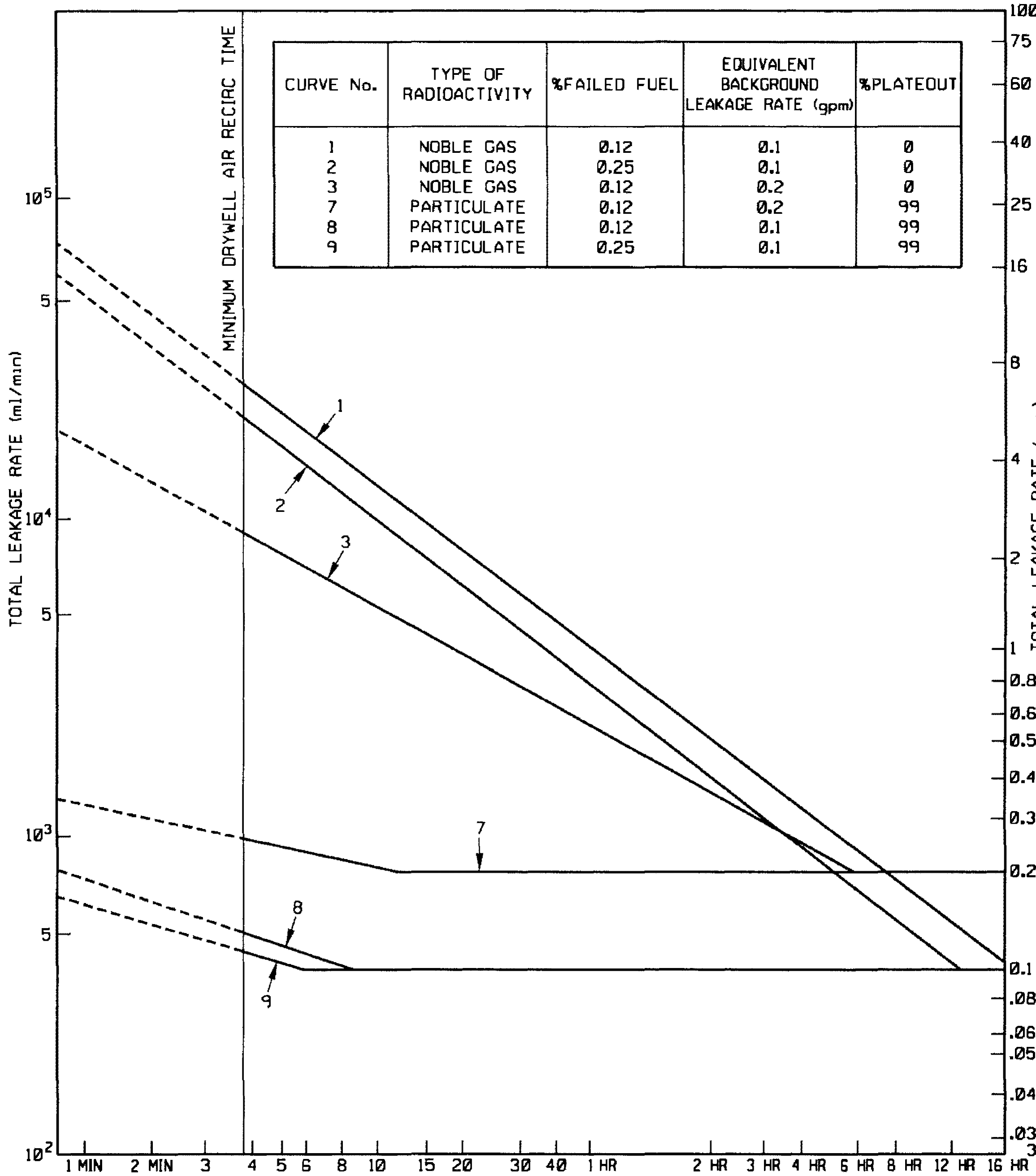
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	CONDUCTANCE VERSUS pH AS A FUNCTION OF CHLORIDE CONCENTRATION OF AQUEOUS SOLUTION AT 25° C FIGURE 5.2-15



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	CALCULATED LEAK RATE VERSUS CRACK LENGTH AS A FUNCTION OF APPLIED HOOP STRESS FIGURE 5.2-16



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	AXIAL THROUGH WALL CRACK LENGTH DATA CORRELATION FIGURE 5.2-17 [HISTORICAL INFORMATION]



CURVE No.	TYPE OF RADIOACTIVITY	%FAILED FUEL	EQUIVALENT BACKGROUND LEAKAGE RATE (gpm)	%PLATEOUT
1	NOBLE GAS	0.12	0.1	0
2	NOBLE GAS	0.25	0.1	0
3	NOBLE GAS	0.12	0.2	0
7	PARTICULATE	0.12	0.2	99
8	PARTICULATE	0.12	0.1	99
9	PARTICULATE	0.25	0.1	99

GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	REACTOR COOLANT LEAK DETECTION RESPONSE TIME FOR DRYWELL AIRBORNE RADIOACTIVITY MONITORS FIGURE 5.2-18

5.3 REACTOR VESSEL

5.3.1 REACTOR VESSEL MATERIALS

5.3.1.1 Materials Specifications

[HISTORICAL INFORMATION] [The materials used in the reactor pressure vessel and appurtenances are shown in Table 5.2-4 together with the applicable specifications.]

5.3.1.2 Special Processes Used for Manufacturing and Fabrication

[HISTORICAL INFORMATION] [The reactor pressure vessel is primarily constructed from low alloy, high strength steel plate and forgings. Plates are ordered to ASME SA 533 Grade B, Class 1, and forgings to ASME SA 508, Class 2 These materials are melted to fine grain practice and are supplied in the quenched and tempered condition. Further restrictions include a requirement for vacuum degassing to lower the hydrogen level and improve the cleanliness of the low alloy steels. Materials used in the core beltline region also specify limits of 0.12 percent maximum copper and 0.015 percent maximum phosphorus content in the base materials and weld materials.

Studs, nuts, and washers for the main closure flange are ordered to ASME SA 540, Grade 23 or Grade 24. Welding electrodes are low hydrogen type ordered to ASME SFA 5.5.

All plate, forgings, and bolting are 100 percent ultrasonically tested and surface examined by magnetic particle methods or liquid penetrant methods in accordance with ASME Code, Section III, subsection NB standards. Fracture toughness properties are also measured and controlled in accordance with subsection NB requirements.

All fabrication of the reactor pressure vessel is performed in accordance with buyer approved drawings, fabrication procedures, and test procedures. The shells and vessel heads are made from formed plates, and the flanges and nozzles from forgings. Welding performed to join these vessel components is in accordance with procedures qualified per ASME Code, Sections III and IX requirements. Weld test samples are required for each procedure for major vessel full penetration welds. Tensile and impact tests are performed to determine the properties of the base metal, heat affected zone, and weld metal.

Submerged arc and manual stick electrode welding processes are employed. Electroslag welding is not permitted. Preheat and interpass temperatures employed for welding of low alloy steel meet or exceed the requirements of ASME Code, Section III, subsection NA. Post weld heat treatment at 1100 F minimum is applied to all low alloy steel welds.

Radiographic examination is performed on all pressure containing welds in accordance with requirements of ASME Code, Section III, subsection NB 5320. In addition, all welds are given a supplemental ultrasonic examination.

The materials, fabrication procedures, and testing methods used in the construction of BWR reactor pressure vessels meet or exceed requirements of ASME Code Section III, Class I vessels.]

5.3.1.3 Special Methods for Nondestructive Examination

[HISTORICAL INFORMATION] [The materials and welds on the reactor pressure vessel were examined in accordance with methods prescribed and met the acceptance requirements specified by ASME Code, Section III. In addition, the pressure retaining welds were ultrasonically examined to the requirements of ASME Code, Section XI, in Appendix I. See subsection 5.2.4 for details of the ISI program.

[HISTORICAL INFORMATION] [

5.3.1.4 Special Controls For Ferritic and Austenitic Stainless Steels

5.3.1.4.1 Compliance With Regulatory Guides

5.3.1.4.1.1 Regulatory Guide 1.31, Control of Stainless Steel Welding

Controls on stainless steel welding are discussed in subsection 5.2.3.4.2.

5.3.1.4.1.2 Regulatory Guide 1.34, Control of Electroslag Weld Properties

Electroslag welding was not employed for the reactor pressure vessel fabrication.

5.3.1.4.1.3 Regulatory Guide 1.43, Control of Stainless Steel Weld Cladding of Low Alloy Steel Components

Reactor pressure vessel specifications require that all low alloy steel be produced to fine grain practice. The requirements of this regulatory guide are not applicable to BWR vessels.

5.3.1.4.1.4 Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel

Controls to avoid severe sensitization are discussed in subsection 5.2.3.4.1.

5.3.1.4.1.5 Regulatory Guide 1.50, Control of Preheat Temperature for Welding Low Alloy Steel

Preheat controls are discussed in subsection 5.2.3.3.2.

5.3.1.4.1.6 Regulatory Guide 1.71, Welder Qualification for Areas of Limited Accessibility

Qualification for areas of limited accessibility is discussed in subsection 5.2.3.3.2.3.

5.3.1.4.1.7 Regulatory Guide 1.99, Effects of Residual Elements on Predicted Radiation Damage to Reactor Pressure Vessel Materials

Predictions for changes in transition temperature and upper shelf energy were made in accordance with the requirements of Regulatory Guide 1.99.]

5.3.1.5 Fracture Toughness

5.3.1.5.1 Compliance with 10 CFR 50 Appendix G

Appendix G of 10 CFR 50, as revised in May 1983, is interpreted for Class 1 RCPB components of the BWR/6 reactor design and complied with as discussed in subsection 5.3.2 and below, with the following exception:

1. A minimum boltup and pressurization temperature of 70 F is called for, which is at least 60 F above the flange region RT_{NDT}. This exceeds the minimum RT_{NDT} temperature required by ASME Code Section III, Paragraph G-2222(c), Summer 1976 and later editions.

A flange region flaw size less than 10 percent of the wall thickness can be detected at the outside surface of the flange to shell and head junctions where stresses due to boltup are most limiting.

Method of Compliance

The following items A through G are the interpretations and methods used to comply with Appendix G of 10 CFR 50. [HISTORICAL INFORMATION] [Item H reports the fracture toughness test results and the background information used as the basis to show compliance with 10 CFR 50, Appendix G. The calibration of temperature instruments and CVN impact test machines used in impact testing by the supplier complies with Paragraph NB-2360 of the ASME Code as required by 10 CFR 50, Appendix G, III.B.3.]

A. [HISTORICAL INFORMATION] [Specimen Orientation for Original Qualification Versus Surveillance

Charpy V-notch tests as defined in NB-2321.2 are to be conducted on both unirradiated and irradiated ferritic materials. However, the special beltline longitudinally oriented Charpy specimens required by the general reference NB-2300 and, specifically, NB-2322.2(a) (6) are not to be included in the surveillance program, because the transverse specimens are limiting with regard to toughness.]

B. [HISTORICAL INFORMATION] [Records and Procedures for Impact Testing

It is understood that Appendix G allows the component manufacturer the liberty of assigning to qualified subcontractors, such as material suppliers, the actual preparation of written impact testing procedures. Personnel were qualified to written impact testing procedures. For the Grand Gulf reactor pressure vessel, records were not sufficient to document full compliance to Appendix G; however, there are sufficient records to document that the technical requirements are met.]

C. [HISTORICAL INFORMATION] [Charpy-V Curves for the RPV Beltline

It is understood that the orientation of impact test specimens shall comply with the requirements of NB-2322(a)4 (transverse specimen) for plate material as opposed to NB-2322(a) (6) (longitudinal specimen). This interpretation of NB-2322 results in meaningful and conservative beltline curves of unirradiated materials for comparison with the results of surveillance program testing of irradiated transverse base metal specimens and also allows this curve to comply with ASTM E 185-73.

It is understood that the number, type, and locations of specimens necessary for the full curves of Charpy toughness are those required to comply with paragraphs 4.3 and 4.4 of ASTM E 185-73. This interpretation is considered necessary to ensure that the adjusted reference temperature of irradiated base metal, heat-affected zone and weld metal called for in Appendix H can be based on data directly comparable to the unirradiated reference temperature.

For Grand Gulf Unit 1, (originally) all beltline weld materials (3) and one of the limiting (adjusted reference temperature) beltline plate materials were used for selection of surveillance specimen base material and weld material to provide a conservative adjusted reference temperature for the beltline material. The weld test plate for the surveillance program specimens had the principal working direction perpendicular to the weld seam to ensure that heat-affected zone specimens were parallel to the principal working direction in order to represent the longitudinal weld seams in the Grand Gulf beltline.

The GGNS surveillance specimen program is currently administered in accordance with the BWRVIP Intergrated Surveillance Program (ISP) as described below in Section 5.3.1.6.1.

D. [HISTORICAL INFORMATION] [Alternative Procedures for the Calculation of Stress Intensity Factor

Stress intensity factors were calculated by the methods of Appendix G to Section III of the ASME Code. Discontinuity regions were evaluated, as well as shell and head areas, as part of the detailed thermal and stress analysis in the vessel stress report. Equivalent margins of safety to those required for shells and heads were demonstrated using a ¼T defect at all locations, with the exception of the main closure flange to head and shell discontinuity locations; there it was found that additional restriction on operating limits would be required for outside surface flaw size greater than 0.24 inches at the outside surface of the flange to shell joint (based on additional analyses made for BWR/6 reactor vessels). It has been demonstrated using a test mockup of these areas that smaller defects can be detected by the ultrasonic inservice examination procedures required at the adjacent weld joint. Since the stress intensity factor is greatest at the outside surface of the flange to shell and head joints, a flaw can also be detected by outside surface examination techniques.]

E. Fracture Toughness Margins in the Control of Reactivity

Appendix G of the ASME Code Section III (1971 Edition with Addenda to and including Winter 1972 or later), "Protection Against Non-ductile Failure," was used in determining pressure/ temperature limitations for all phases of plant operation. Additionally, when the core is critical, a 40 F temperature allowance is included in the reactor vessel operating pressure versus temperature limits to account for operational occurrences in the control of reactivity. Pressure-temperature limitations are currently determined as described below in Sections 5.3.1.6 and 5.3.2.1 and maintained in the PTLR.

F. Bolting Materials

Bolting meets the 45 ft-lb and 25 mils lateral expansion requirements at 10 F for Grand Gulf. The reactor vessel head flange bolt-up temperature limits are controlled in accordance with the pressure temperature limit curves as described in the PTLR.

G. Upper Shelf Energy for Beltline

For the Grand Gulf Unit 1 reactor pressure vessel, all beltline materials comply with the requirement of an initial 75 ft-lb minimum upper shelf Charpy V-notch energy (transverse direction). Appendix G of 10CFR50 sets a limit on the upper shelf energy of the beltline materials that they must remain above 50 ft-lbs at all times during reactor operation, including the period of extended operation. The effects of neutron radiation on the upper shelf energy level are accounted for by relevant surveillance capsule data as described in Section 5.3.1.6. The GGNS materials were evaluated using Regulatory Guide 199, Revision 2, based on the peak 1/4T fluence for 54 EFPY as calculated for each location identified in Table 5.3-3a and all materials, with the exception of one, remain above the 50 ft-lb criteria. For the one plate material in shell ring 3, insufficient information is available to determine the initial (unirradiated) upper shelf. This heat C2779-1 has an average transverse Charpy test result of 52 ft-lbs (average of 50, 52, and 42 ft-lbs) and a maximum of 50% shear. In addition, copper content is not available and the limiting chemistry was obtained from purchase in BWRVIP-135, Revision 3 and BWRVIP-74-A to qualify the beltline material for upper shelf energy. The results of this analysis showed that the decrease in upper shelf energy for this material is bounded by the requirements in BWRVIP-74-A for 54 EFPY (Ref.7).

H. [HISTORICAL INFORMATION] [Results of fracture toughness tests for Grand Gulf Unit 1 are reported in Tables 5.3-1 and 5.3-2.]

I. Reactor Pressure Vessel Circumferential Weld Inspection Relief

The ASME Code, Section XI, Table IWB-2500-1, requires inspection of all RPV welds at regular intervals. The NRC granted relief from performing these specific ASME required examinations at GGNS under Generic Letter 98-05 (Ref. 12). The basis for this relief was the BWRVIP-05 report, “BWR Reactor Pressure Vessel Shell Weld Inspection Recommendation,” dated July 28, 1998, which concluded that the conditional failure probabilities for BWR RPV circumferential welds are orders of magnitude lower that those in the axial shell welds. Subsequent to receiving this relief, 60-year (54 EFPY) fluences based on EPU conditions were used to validate the inspection relief for the period of extended operation. This analysis confirmed that the circumferential weld inspection relief remains qualified for the extended license, including EPU operation (Ref. 13).

5.3.1.6 Material Surveillance

5.3.1.6.1 Compliance with Reactor Vessel Material Surveillance Program Requirements

The materials surveillance program monitors changes in the fracture toughness properties of ferritic materials in the reactor vessel beltline region resulting from their exposure to neutron irradiation and thermal environment.

The Grand Gulf material surveillance program is administered in accordance with the BWR Vessel and Internals Project Integrated Surveillance Program (BWRVIP ISP) as described in Reference 5 . The ISP combines the U.S. BWR surveillance programs into a single integrated program. This program uses similar heats of materials in the surveillance programs of BWRs to represent the limiting materials in other vessels. It also adds data from the BWR Supplemental Surveillance Program (SSP). Per the BWRVIP ISP. No capsules are scheduled to be withdrawn from the Grand Gulf vessel. Other plants will remove and test specimens that represent the Grand Gulf vessel.

A plant-specific evaluation of Grand Gulf's target vessel materials, the ISP surveillance materials assigned by the ISP test matrix to represent those target materials, and the key surveillance results for the represented materials is provided in Reference 8. The target vessel materials are weld material 5P6214B and plate material A1224-1, C2594-2 and the ISP representative materials are 5P6214B and A1224-1, respectively. The BWRVIP ISP concludes that the ISP surveillance data should be used to revise the projected adjusted reference temperature (ART) value for the target vessel plate and weld using the methods in Regulatory Guide 1.99, Revision 2, in accordance with 10CFR50, Appendix G. Refer to Section 5.3.1.6.3 for a discussion on the determination of the projected ART values used for developing the pressure-temperature (P-T) limit curves which are discussed in Section 5.3.2.

The three original surveillance capsules containing the reactor vessel materials specimens under the previous individual Grand Gulf surveillance program are reserved in the reactor for contingency purposes. Each in-reactor capsule contained 36 Charpy V-notch specimens in accordance with 10 CFR 50, Appendix H and ASTM E 185-73 which was in effect at the time the surveillance capsules were loaded. The capsule loading consists of 12 specimens each of base metal, weld metal, and heat-affected zone material.

[HISTORICAL INFORMATION] [The specimens were manufactured from a plate actually used in the beltline region and a weld typical of those in the beltline region and thus represent base metal, weld material, and the weld heat-affected zone material. Specimen materials are identified with properties in Tables 5.3-1 and 5.3-2. Table 5.3-6 provides the chemical composition for each reactor vessel beltline weld, and plate. Figures 5.3-9 and 5.3-13 through 5.3-15 define the beltline location and the location of plates and weld seams in the beltline. The plate and weld were heat treated in a manner which simulated the actual heat treatment performed on the core region shell plates of the completed vessel.

WITHDRAWAL SCHEDULE

CAPSULE NUMBER	VESSEL LOCATION	LEAD** FACTOR	WITHDRAWAL SCHEDULE
131C8981G1 - NO1	3˚	0.46	deferred*
131C8981G1 - NO2 or N03	177˚	0.46	deferred*
131C8981G1 - NO3 or N02	183˚	0.46	deferred*

EFPY - Effective Full Power Years

Fracture toughness testing of irradiated capsule specimens will be in accordance with requirements of 10 CFR 50, Appendix H as revised in May 1983, and ASTM E 185-82.

* Capsule No. 1 was withdrawn during RFO7 and returned to the vessel during RFO8 with the specimens intact. This action was approved by the NRC in Amendment No. 127 to the Operating License. All GGNS capsules were deferred from withdrawal and testing in accordance with References 3 and 4.

**Updated Lead Factor is 0.43 based on the 3˚ Surveillance Capsule Dosimetry at EOC 13 (Evaluated in Reference 6)]

5.3.1.6.2 Neutron Fluence

As described in Section 4.3.2.8, updated fluence calculations have been performed in accordance with Regulatory Guide 1.190.The 3D neutron transport calculations were used to determine detailed fluence profiles at the end of the cycle 21 (28.088 EFPY), and projected to exposures of 35 EFPY and 54 EFPY (Ref. 6). The 35-EFPY peak fluence for the reactor vessel inner surface used for determination of the P-T limit curves, is 2.34E+18 n/cm^2 and for 54 EFPY it is 4.02E+18 n/cm^2. Fluence for the 1/4 thickness location is determined using the displacements per atom (dpa) attenuation method in accordance with RG 1.99, Rev. 2 (Ref. 7). As described in Section 2.1.4 of the PUSAR, EPU does increase the fluence for the reactor vessel beltline region; however the EPU fluence for the reactor vessel safe-end welds and piping remain well below the 5.0E+20 n/cm^2 fluence threshold for IASCC concerns for stainless steel.

5.3.1.6.3 Predicted Irradiation Effects on Vessel Beltline Materials

The initial RT_{NDT} is the nil ductility transition temperature for the unirradiated RPV materials as defined in Paragraph NB-2331 of Section III (Division 1, Class 1 Components) of the ASME boiler and Pressure Vessel Code. The Charpy energy data used to determine the initial RT_{NDT} values are tabulated from the GGNS Certified Material Test Reports. The adjusted reference temperature (ART) is the reference temperatures for GGNS are shown in Table 5.3-3a and 5.3-3b for 35 EFPY and 54 EFPY, respectively.

Using the updated peak neutron fluence (Ref.6) and the latest surveillance capsule test data available from the BWRVIP ISP (Ref. 8) the ART values were calculated for 35 and 54 EFPYs (Ref. 7). The evaluation of ART for all beltline plates and welds was performed using RG 1.99, Revision 2, methods and the results are show in Tables 5.3-3a for 35 EFPY and 5.3-3b for 54 EFPY. These updated tables include components outside the originally defined vessel beltline region due ti the updated fluences described in Section 4.3.2.8 that extends the beltline region to include shell 3 materials. As shown in these tables, the ISP representative plate material ART value bounds the plant-specific plate materials at 35 EFPY, but the plant specific materials bound at 54 EFPY. Guidance from BWRVIP-135, Revision 3, states that, because the ISP material is in the GGNS vessel, it must be considered in development of the P-T limit curves. The ISP and plant-specific plate materials bound the weld materials, however due to the stresses inherit in the nozzles, the N6 and N12 nozzle welds are considered in the vessel beltline P-T limit curve evaluation to assure the most limiting curve is generated. The ART is evaluated against a maximum value of 200 degress F. The maximum ART value at 54 EFPY is 511 degrees F. The vessel beltline chemistries were obtained from Reference 10 and are consistent with all known available sources of data for the beltline materials, including the Certified Material Test Reports and previously licensed P-T curve analyses. Chemistries for the surveillance materials were obtained from the BWRVIP ISP. The N12 water lever instrumentation nozzle forging is fabricated from stainless steel so the chemistry from the adjoining plate was used.

It may be noted that earlier revisions of the USFAR included consideration of four weld materials shown to occur in the axial welds in the vessel beltline region (shell ring 2). It has been determined through a review of the GGNS-specific Certified

Materials Test Reports that weld heats 62627260, K22K8511, 627069, and 626677 were used only for weld pick-ups at the ID/OD surface or initial root pass or sealing at the backing bars, which were ground out or subsequently removed. Since these materials are not present in either the 1/4 or the 3/4T locations, they are not required to be considered as part of the beltline welds and are not included in Tables 5.3-3a and 5.3-3b.

5.3.1.6.4 Positioning of Surveillance Capsules and Methods of Attachment

[HISTORICAL INFORMATION] [Surveillance specimen capsules are located at three azimuths at a common elevation in the core beltline region. The sealed capsules are not attached to the vessel but are in seal welded, capsule holders. The capsule holders are mechanically retained by capsule holder brackets welded to the vessel cladding as shown in Figure 5.3-3. Since reactor vessel specifications require that all low alloy steel pressure vessel boundary material be produced to fine-grain practice, underclad cracking is of no concern. The capsule holder brackets allow the removal and reinsertion of capsule holders. These brackets are designed, fabricated, and analyzed to the requirements of ASME Code, Section III. A positive spring loaded locking device is provided to retain the capsules in position throughout any anticipated event during the lifetime of the vessel.

The January 1, 1984 issue of 10 CFR 50, Appendix H Paragraph II, permits the attachment of the capsule holder to the vessel wall, provided construction and in-service inspection of the attachment and attachment welds meet the requirements for permanent structural attachments to the reactor vessel given in Sections III and XI of the ASME Code, respectively.

Documents provided by General Electric for the attachment are discussed below.

Figure 5.3-3a, Surveillance Bracket Outline, gives the details of the weld prep at each of the 3 points where each of the three bracket assemblies attach to the vessel wall.

Figure 5.3-3b, Vessel & Components, specifies a groove weld with a 0.12-inch fillet weld at each of the attachment points, and specifies their location on the surveillance bracket weld buildup pads supplied with the reactor vessel. It also specifies root pass and final accessible surface liquid penetrant examinations.

In addition, document 21A2046, Rev. 5, Welding and Inspection Requirements for Assembly of Reactor Components, specifies the requirements for the weld filler material, weld procedure and welder qualifications, and liquid penetrant examinations. It also requires submittal of the welding procedure and examination procedure for approval by General Electric prior to use. Other requirements such as miscellaneous process materials controls, cleaning, and heat input controls are included in this document. The weld procedure and welders are required to be qualified in accordance with Section IX and Section III, NB4000 of the ASME B&PV Code.]

The bracket attachment welds will be visually inspected in accordance with Examination Category B-N-2 of ASME Section XI. Details of the inspection Program are contained in the Program Section for ASME Section XI, Div. I Inservice Inspection Program.

[HISTORICAL INFORMATION] [In areas where brackets such as the surveillance specimen holder brackets are located, additional non-destructive examinations are performed on the vessel base metal and stainless steel weld deposited cladding or weld buildup pads during vessel manufacture. The base metal is ultrasonically examined by straight beam techniques to a depth at least equal to the thickness of the bracket being joined. The area examined is the area of the subsequent attachment weld plus a band around this area of width equal to at least half the thickness of the part joined. The required stainless steel weld deposited cladding is similarly examined. The full penetration welds are liquid penetrant examined to ASME Code, Section III standards. Cladding thickness is required to be at least 1/8”.

The above requirements have been successfully applied to a variety of bracket designs which are attached to weld deposited stainless steel cladding or weld buildups in many operating BWR reactor pressure vessels.

Inservice inspection examinations of core beltline pressure retaining welds are performed from the outside surface of the reactor pressure vessel. If a bracket were located at or adjacent to a vessel shell weld, it would not interfere with the straight beam or half node angle beam in-service inspection ultrasonic examinations performed from the outside surface of the vessel.]

5.3.1.6.5 Time and Number of Dosimetry Measurements

[HISTORICAL INFORMATION] [GE provides a separate neutron dosimeter so that fluence measurements may be made at the vessel ID during the first fuel cycle to verify the predicted fluence at an early date in plant operation. This measurement is made over this short period to avoid saturation of the dosimeters now available. Once the fluence-to-thermal power output is verified, no further dosimetry is considered necessary because of the linear relationship between fluence and power output. It will be possible, however, to install a new dosimeter, if required, during succeeding fuel cycles. Also surveillance specimen capsules include dosimetry which may provide additional data for use in predicting fluence levels.]

5.3.1.7 Reactor Vessel Fasteners

[HISTORICAL INFORMATION] [The reactor vessel closure head (flange) is fastened to the reactor vessel shell flange by multiple sets of threaded studs and nuts. The lower end of each stud is installed in a threaded hole in the vessel shell flange. A nut and washer are installed on the upper end of each stud. The proper amount of preload can be applied to the studs by a sequential tensioning using hydraulic tensioners. The design and analysis of this area of the vessel is in full compliance with all requirements of ASME Code, Section III, Class I. The material for studs, nuts and washers is SA-540 Grade B23 or B24 in the 130,000 psi specified minimum yield strengths level.

Hardness tests are performed on all main closure bolting to demonstrate that heat treatment has been properly performed. A minimum of 45 ft-lbs Charpy V-notch, CV, energy and 25 mils lateral expansion is required at the lowest service temperature. The maximum reported ultimate tensile strength was below the 170,000 psi maximum specified in Regulatory Guide 1.65. Also, the Charpy impact test requirements of Appendix G were satisfied at +10 F, compared to the requirement of 45 ft-lbs at 70 F. Studs, nuts, and washers are ultrasonically examined in accordance with Section III, NB-2585 and the following additional requirements:

a. Examination was performed after heat treatment and prior to machining threads.

b. Straight beam examination was performed on 100 per- cent of each stud. Reference standard for the radial scan was a 1/2-inch-diameter flat bottom hole having a depth equal to 10 percent of the material thickness For the end scan the standard of NB-2585 was used.

c. Nuts and washers were examined by angle beam from the outside circumference per ASME SA-388 in both the axial and circumferential directions.

The surface examinations of NB-2583 are applied after heat treatment and threading.

There are no metal platings applied to closure studs, nuts, or washers. A phosphate coating was applied to threaded areas of studs and nuts and bearing areas of nuts and washers to assist in retaining lubricant on these surfaces.]

5.3.2 Pressure/Temperature Limits

5.3.2.1 Limit Curves

To accommodate the irradiation effects causing embrittlement of the reactor vessel materials analyses are performed to determine acceptable heatup and cooldown rates of temperature change based on maximum tensile stress allowed for the vessel. Pressure-Temperature (P-T) limits are established to ensure the structural integrity of the ferritic components of the RPV during any condition of normal operation, including Anticipated Operational Occurrences and hydrostatic tests. The P-T limits are derived using the ART values described in Section 5.3.1.6.3, which are fluent dependent relative to elapsed time and is the indicator or value used to predict the radiation embrittlement effects of the materials in the GGNS reactor vessel beltline. A set of P-T limit curves are developed to present steam dome pressure versus minimum vessel metal temperature incorporating appropriate non-beltline limits and irradiation effects in the beltline.

The methodology used to generate the P-T limit curves has been approved by the NRC and is described in Section 43 of Reference 11. The 1998 Edition of the ASME Boiler and Pressure Vessel Code including 2000 Addenda was used in the evaluation. The P-T curves are developed using geometry of the RPV shells and discontinuities, the initial RT_{NDT} of the RPV materials, and the ART values.

Individual P-T limit curves are developed to identify operating limits for various regions of the reactor vessel and for various operating scenarios. Composite curves are then generated to represent the most limiting set of conditions to envelop all the individual curves. These composite curves are generated for the hydrostatic pressure test (Curve A), for core not critical conditions (Curve B), and for core critical conditions (Curve C). P-T limit curves are re-evaluated for each core reload and are documented in the Pressure Temperature limits Report (PTLR) approved for that fuel cycle. The P-T limit curves are maintained in the PTLR and include curves that are valid for the current licensed period of approximately 35 EFPY and also include curves that are valid for an extended plant operating period of approximately 54 EFPY. Compliance with the curves in the PTLR is required by the Technical Specifications and helps to ensure that GGNS continues to meet the requirements of 10CFR50, Appendix G, and 10CFR50.60.

5.3.2.1.1 Temperature Limits for Boltup

A minimum temperature of 70 F is required for the closure studs for Grand Gulf Unit 1. The flanges and adjacent shell are required to be warmed to minimum temperatures of 70 F before they are stressed by the full intended bolt preload (all bolts fully tightened). The boltup limits for the flange and adjacent shell region are based on a minimum metal RT_{NDT} of +60 degrees F. The maximum through-wall temperature gradient from continuous heating or cooling of 100 degrees per hour was considered. The safety factors applied were as specified in the ASME Code, Appendix G. The fully preloaded boltup limits are shown on the P-T limit curves shown in the PTLR as Figures 1 and 2 for 35 EFPY and 54 EFPY, respectively.

5.3.2.1.2 Pressure Temperature Limits for Inservice Leak and Hydrostatic Testing, Curve A

The initial hydrostatic test performed prior to fuel load was based on 10 CFR 50, Appendix G, IV.A.2 at 1563 psig with a minimum temperature of 100˚F. However, inservice leakage and hydrostatic test pressures and temperatures are limited by fracture toughness analysis that account for exposure of the reactor pressure vessel to neutron fluence.

Whereas the beltline limits for the preoperational hydrostatic test were based on an initial ART_{NDT} of 0˚F for plate material, the beltline limits for inservice pressure tests are based on an adjusted RT_{NDT}(ART_{NDT}) for the limiting RPV material. Since the ART_{NDT} represents an increase from the initial RT_{NDT} based on fluence, Curve A is adjusted as fluence is accumulated. The determination of ART_{NDT} is in accordance with Regulatory Guide 1.99 and is based on the neutron fluence at ¼T of the reactor vessel wall in the beltline area.

The P-T limit curves are shown in the PTLR as Curve A in Figures 1 and 2 for 35 EFPY and 54 EFPY, respectively. The composite curves for the hydrostatic test are based on a heatup and cooldown temperature rate of 20 degrees F at all times.

5.3.2.1.3 Operating Limits for Non-Critical Core Conditions, Curve B and Core Critical Conditions, Curve C

In addition to the adjustment of the initial ART_{NDT} caused by the effects of fluence as described in 5.3.2.1.2, Curves B and C also represent the results of analysis for temperature gradients and thermal stresses. The fracture toughness analysis is done for the normal heatup and cooldown rate of 100˚F/hour.

The P-T limit curves are shown in the PTLR as Curve B for non-critical core conditions and as Curve C for core critical conditions in Figures 1 and 2 for 35 EFPY and 54 EFPY, respectively. Curve C is the limits of Curve B plus 40˚F margin as required for criticality in accordance with Appendix G.

5.3.2.1.4 Reactor Vessel Annealing

In-place annealing of the reactor vessel because of radiation embrittlement is unnecessary, because the predicted value in transition of adjusted reference temperature does not exceed 200 F, and the upper shelf energy is not below 50 ft-lb.

For design purposes, the adjusted reference temperature for BWR vessels is predicted using the procedures in Regulatory Guide 1.99.

5.3.2.1.5 Non-Beltline Information

[HISTORICAL INFORMATION] [The Grand Gulf Unit 1 vessel was procured to meet the requirements of the ASME Code Section III, 1971 Edition with Winter 1972 Addenda, which are consistent with the toughness testing requirements of 10 CFR 50, Appendix G.

A review of quality assurance records (Documented Deviations, from the vendor CBI Nuclear) reveals no deviations from the below listed fracture toughness purchase requirements limits:

1. RT_{NDT} no greater than +10 F for the shell course, head, and closure flange.
2. RT_{NDT} no greater than -20 F for nozzle forgings.
3. RT_{NDT} no greater than -20 F for low alloy weld metal used to join base or weld materials requiring impact testing.]

5.3.2.1.6 Other Ferritic Reactor Coolant Pressure Boundary Materials

[HISTORICAL INFORMATION] [The subject materials were impact tested and are in compliance with 10 CFR 50, Appendix G. Specific components, applicable code requirements, and impact test temperatures are:

1. Main Steam Pipe - ASME III, 1974 and Summer 1974 Addenda, +60 F
2. Main Steam Isolation Valve - ASME III, 1974, +60 F
3. Safety/Relief Valve (8" x 10") - ASME III, 1974 and Summer 1976 Addenda, +60 F
4. HPCS Isolation Valve - ASME III, 1971 and Winter 1973 Addenda, +40 F
5. Flued Head - ASME III, 1974 and Summer 1974, +60 F

Ferritic piping employed in the reactor coolant pressure boundary (RCPB) (Class 1) was surveyed to identify the limiting case using maximum wall thickness as the criteria. Feedwater system piping was identified as the limiting case. The material test report for a representative pipe spool used at Grand Gulf was submitted via separate letter, L. F. Dale, MP&L (SERI), to H. R. Denton, NRC, dated August 21, 1981. This report includes stated compliance with ASME Section III as required by Appendix G to 10 CFR 50. A brief data summary from that report is provided below. Fracture toughness data on all other ferritic piping in the RCPB are available for review at the Grand Gulf Nuclear Station.

Pipe Spool Number	Wall Thickness	Size	Material	Test Temperature	Heat Number
Q1B21G030-5-8	1.219"	24"	SA-106 Grade C	+50 F	L2505

Ferritic valves employed in the reactor coolant pressure boundary (RCPB) (Class 1) were surveyed to identify the limiting component. Maximum member thickness was used as the criteria.

The limiting component identified is the feedwater outboard containment isolation check valve supplied by Atwood & Morrill. The pressure boundary parts consist of the body, cover, and disc. The data contained in the certified material test report have been summarized in Table 5.3-8. This report was submitted via separate letter, L. F. Dale, MP&L, to H. R. Denton, NRC, dated August 21, 1981, and includes affirmation by the supplier of compliance with Article NB 2000 of ASME Section III for the materials and construction of this component. Fracture toughness data for all other ferritic valves in the RCPB are available for review at the Grand Gulf Nuclear Station.]

5.3.2.2 Operating Procedures

By comparison of the pressure vs temperature limits in subsection 5.3.2.1 with intended normal operating procedures for the most severe upset transient, it is shown that the limits will not be exceeded during any foreseeable upset condition. Reactor operating procedures have been established such that actual transients will not be more severe than those for which the vessel design adequacy has been demonstrated. Of the design transients, the upset condition producing the most adverse temperature and pressure condition anywhere in the vessel heads and/or shell areas has a minimum fluid temperature of 250 F and a maximum pressure peak of 1180 psig. An automatic scram precedes the pressure and temperature transients associated with the upset condition.

Normal operating procedures also include plant operation with the reactor vessel at vacuum (i.e., less than atmospheric pressure). This condition may occur during startup or shutdown or any abnormal condition in which the MSIVs are open, the condenser has vacuum, and the vessel is depressurized. The reactor vessel has been analyzed for that condition and the conclusion was that the vessel is in no danger of collapse from external pressure or a vacuum from the condenser (Ref. 9).

5.3.3 Reactor Vessel Integrity

[HISTORICAL INFORMATION] [The reactor vessel was fabricated for General Electric's Nuclear Energy Division by CBI Nuclear Co. and was subject to the requirements of General Electric's Quality Assurance program.

The CBI Nuclear Co. has had extensive experience with GE reactor vessels and has been the primary supplier of GE domestic reactor vessels and some foreign vessels since the company was formed in 1972 from a merger agreement between Chicago Bridge and Iron Co. and General Electric. Prior experience by the Chicago Bridge and Iron Co. with GE reactor vessels dates back to 1966.

Assurance was made that measures were established requiring that purchased material, equipment, and services associated with the reactor vessels and appurtenances conform to the requirements of the subject purchase documents. These measures included provisions, as appropriate, for source evaluation and selection, objective evidence of quality furnished, inspection at the vendor source and examination of the completed reactor vessels.

General Electric provided inspection surveillance of the reactor vessel fabricator's in-process manufacturing, fabrication, and testing operations in accordance with GE's Quality Assurance program and approved inspection procedures. The reactor vessel fabricator was responsible for the first level inspection of his manufacturing, fabrication, and testing activities and General Electric is responsible for the first level of audit and surveillance inspection.

Adequate documentary evidence that the reactor vessel material, manufacture, testing, and inspection conform to the specified quality assurance requirements contained in the procurement specification is available at the fabricator plant site.

Regulatory Guide 1.2
General Compliance or Alternate Approach Assessment: For commitment, revision number, and scope see Appendix 3A.

The Regulatory Guide states that potential reactor pressure vessel brittle fracture which may result from emergency core cooling system operation need not be reviewed in individual cases if no significant changes in presently approved core and pressure vessel designs are proposed. Should it be considered that the margin of safety against reactor pressure vessel brittle fracture due to emergency core cooling system operation is unacceptable, an engineering solution, such as annealing, could be applied to ensure adequate recovery of the fracture toughness properties of the vessel material. This Regulatory Guide requires that available engineering solutions be outlined and requires that it be demonstrated that the design does not preclude their use.

The reactor pressure vessel employs no significant core or vessel design changes from previously approved BWR pressure vessels such as Browns Ferry, all units.

An investigation of the structural integrity of boiling water reactor pressure vessels during a design basis accident (DBA) has been conducted (refer to NEDO-10029, “An Analytical Study on Brittle Fracture of GE-BWR Vessel Subject to the Design Basis Accident”). It has been determined, based on methods of fracture mechanics, that no failure of the vessel by brittle fracture as a result of DBA will occur.

The investigation included:

1. A comprehensive thermal analysis considering the effect of blowdown and the low pressure coolant injection (LPCI) system reflooding.

2. A stress analysis considering the effects of pressure, temperature, seismic load, jet load, dead weight, and residual stresses.

3. The radiation effect on material toughness (NDTT shift and critical stress intensity).

4. Methods for calculating crack tip stress intensity associated with a nonuniform stress field following the design basis accident.

This analysis incorporated very conservative assumptions in all areas (particularly in the areas of heat transfer, stress analysis, effects of radiation on material toughness, and crack tip stress intensity). Therefore, the results reported in NEDO-10029 provide an upper bound limit on brittle fracture failure mode studies. Because of the upper bound approach, it is concluded that catastrophic failure of the pressure vessel due to the DBA is shown to be impossible from a fracture mechanics point of view. In the case studies, even if an acute flaw does form on the vessel inner wall, it will not propagate as the result of the DBA.] The conclusions reached in this report have been further supported by a more recent analysis for 54 EFPY (Ref.7) which was based on a more representative fluence. Due to increased fluence values resulting from EPU and license renewal, this analysis was revisited. A revisited analysis utilized updated fluences and a calculated adjusted reference temperature (ART) value of 51.1 °F at 54 EFPY for the limiting weld material of the RPV. The results of the 60 year (54 EFPY) analysis supported the conclusions drawn in the previous analysis as remaining valid through the period of extended operation.

The criteria of 10 CFR 50, Appendix G are interpreted as establishing the requirements for annealing. Appendix G requires the vessels to be designed for annealing of the beltline only where the predicted value of adjusted RT_{NDT} exceeds 200 F as defined in Paragraph NB-2331 of the ASME Section III Code. This predicted value is not exceeded; therefore, design for annealing is not required.

For further discussion of fracture toughness of the reactor pressure vessel refer to subsection 5.3.1.5.

5.3.3.1 Design

5.3.3.1.1 Description

5.3.3.1.1.1 Reactor Vessel

The reactor vessel shown in Figure 5.3-1 is a vertical, cylindrical pressure vessel of welded construction. The vessel is designed, fabricated, tested, inspected, and stamped in accordance with the ASME Code, Section III, Class 1 including the addenda in effect at the date of order placement, Winter 1972. Design of the reactor vessel and its support system meets seismic Category I equipment requirements. The materials used in the reactor pressure vessel are shown in Table 5.2-4.

The cylindrical shell and top and bottom heads of the reactor vessel are fabricated of low alloy steel; the interior of which is clad with stainless steel weld overlay, except for the top head and nozzle and nozzle weld zones.

In-place annealing of the reactor vessel is unnecessary because shifts in transition temperature caused by irradiation during the 40-year life can be accommodated by raising the minimum pressurization temperature, and the predicted value of adjusted reference temperature does not exceed 200 F. Radiation embrittlement is not a problem outside of the vessel beltline region because the irradiation in those areas is less than 1×10^{1} nvt with neutron energies in excess of 1 MeV.

Quality control methods used during the fabrication and assembly of the reactor vessel and appurtenances assure that design specifications are met.

The vessel top head is secured to the reactor vessel by studs and nuts. These nuts are tightened with a stud tensioner. The vessel flanges are sealed with two concentric metal seal rings designed to permit no detectable leakage through the inner or outer seal at any operating condition, including heating to operating pressure and temperature at a maximum rate of 100 F/hr in any one hour period. To detect seal failure, a vent tap is located between the two seal rings. A monitor line is attached to the tap to provide an indication of leakage from the inner seal ring seal.

5.3.3.1.1.2 Shroud Support

The shroud support is a circular plate welded to the vessel wall and to a cylinder supported by vertical stilt legs from the bottom head, peripheral fuel elements, neutron sources, core plate, top guide, the steam separators, and the jet pump diffusers, and to support laterally the fuel assemblies. Design of the shroud support also accounts for pressure differentials across the shroud support plate, for the restraining effect of components attached to the support, and for earthquake loadings. The shroud support design is specified to meet appropriate ASME Code stress limits.

5.3.3.1.1.3 Protection of Closure Studs

The boiling water reactor does not use borated water for reactivity control. This subsection is therefore not applicable.

5.3.3.1.2 Safety Design Bases

Design of the reactor vessel and appurtenances meets the following safety design bases:

a. The reactor vessel and appurtenances will withstand adverse combinations of loading and forces resulting from operation under abnormal and accident conditions.

b. To minimize the possibility of brittle fracture of the nuclear system process barrier, the following are required:

   1. Impact properties at temperatures related to vessel operation have been specified for materials used in the reactor vessel.

   2. Expected shifts in transition temperature during design life as a result of environmental conditions, such as neutron flux, are considered in the design. Operational limitations assure that NDT temperature shifts are accounted for in reactor operation.

   3. Operational margins to be observed with regard to the transition temperature are specified for each mode of operation.

5.3.3.1.3 Power Generation Design Basis

The design of the reactor vessel and appurtenances meets the following power generation design basis:

a. The reactor vessel has been designed for a useful life of 40 years.

b. External and internal supports that are integral parts of the reactor vessel are located and designed so that stresses in the vessel and supports that result from reactions at these supports are within ASME Code limits.

c. Design of the reactor vessel and appurtenances allows for a suitable program of inspection and surveillance.

5.3.3.1.4 Reactor Vessel Design Data

Reactor vessel design data are contained in Table 5.2-3.

5.3.3.1.4.1 Vessel Support

The vessel supports are discussed in subsections 3.8.3.1.4 and 3.8.3.1.5.

5.3.3.1.4.2 Control Rod Drive Housings

The control rod drive housings are inserted through the control rod drive penetrations in the reactor vessel bottom head and are welded to the reactor vessel. Each housing transmits loads to the bottom head of the reactor. These loads include the weights of a control rod, a control rod drive, a control rod guide tube, a four-lobed fuel support piece, and the four fuel assemblies that rest on the fuel support piece. The housings are fabricated of Type 304 austenitic stainless steel.

5.3.3.1.4.3 In-Core Neutron Flux Monitor Housings

Each in-core neutron flux monitor housing is inserted through the in-core penetrations in the bottom head and is welded to the inner surface of the bottom head.

An in-core flux monitor guide tube is welded to the top of each housing and either a source range monitor/intermediate range monitor (SRM/IRM) drive unit or a local power range monitor (LPRM) is bolted to the seal ring flange at the bottom of the housing (Section 7.6).

5.3.3.1.4.4 Reactor Vessel Insulation

The reactor vessel insulation is of the reflective type and is constructed completely of metal. The outer surface temperature of the insulation is expected to be at 160 F and the heat transfer rate through the insulation is approximately 65 Btu/ hr-ft2 under normal operating conditions. The insulation consists of several self-contained assemblies latched together, each of which can be easily removed and replaced. The insulation assemblies are designed to remain in place and resist permanent damage during a safe shutdown earthquake.

The reactor top head insulation is supported from a structure secured on the bulkhead by means of temporary fasteners. During refueling, the support structure along with the top head insulation is removed. The support structure is designed as seismic Category I equipment. The insulation for the reactor vessel cylindrical surface is supported by brackets welded on the shield wall liner plate.

5.3.3.1.4.5 Reactor Vessel Nozzles

All piping connecting to the reactor vessel nozzles has been designed so it does not exceed the allowable loads on any nozzle.

The vessel top head nozzle is provided with a flange with large groove facing. The drain nozzle is of the full penetration weld design. The recirculation inlet nozzles are located as shown in Figure 5.3-1. Feedwater inlet nozzles, core spray inlet nozzles, and LPCI nozzles all have thermal sleeves. Nozzles connecting to stainless steel piping have safe ends or extensions made of stainless steel. These safe ends or extensions were welded to the nozzles after the pressure vessel was heat treated to avoid furnace sensitization of the stainless steel. The material used is compatible with the material of the mating pipe.

5.3.3.1.4.5.1 Evaluation of Feedwater Nozzle and Sparger Problems

[HISTORICAL INFORMATION] [The mechanisms which have caused cracking in operating BWRs are understood. A summary discussion of the previously observed problems and the solutions incorporated in the Grand Gulf design are presented in the following.

A detailed evaluation of the problems of the feedwater nozzle and sparger is presented in NEDE-21821, BWR Feedwater Nozzle/ Sparger Final Report, March 1978. The solution of the feedwater nozzle and sparger cracking problems involves several elements, including material selection and processing, nozzle clad removal, and thermal sleeve and sparger redesign. The following summarizes the problems that have occurred in the nozzle and sparger and shows the solution implemented at Grand Gulf that eliminates each problem:

PROBLEM	CAUSE	FIX
Sparger arm cracks	Mechanical Fatigue	Eliminate/minimize clearance between thermal sleeve and safe end
	Thermal fatigue	Eliminate low flow stratification by use of top-mounted elbows
Flow hole cracks	Thermal fatigue	eliminate separation by use of converging nozzles
Nozzle cracks	Thermal fatigue	Eliminate clad, control leakage, protect nozzle with multiple sleeves

The sparger vibration has been attributed to a self-excitation caused by instability of leakage flow through the annular clearance between the thermal sleeve and safe end. Tests reported in NEDE-21821, Section 4.1, have shown that the vibration is eliminated if the clearance is reduced sufficiently or sealed. The solution implemented at Grand Gulf uses a two-stage piston ring mounted in the thermal sleeve in conjunction with an interference fit between the sleeve and safe end. This feature is also an essential part of the solution of the nozzle cracking problem and is described later in more detail. Freedom from vibration over a range of conditions has been demonstrated by the tests reported in NEDE-21821, Section 4.

Sparger arm cracking has also been caused by thermal fatigue, both at the flow holes and adjacent to the tee connection with the thermal sleeve. In both cases, excessive cyclic thermal stresses are caused by the exposure of material in a constrained structure to an unstable boundary between cold feedwater fluid and hot reactor fluid. At low feedwater flow, the presence of exit flow holes at the midplane of the sparger allowed the sparger to be only partially filled with cold fluid. This caused a temperature gradient from the top of the sparger to the bottom, with associated bending stresses which changed directly with changes in the flow gradient. At Grand Gulf, location of the exit flow holes at the top of the sparger allows complete filling of the sparger with the feedwater fluid even at low flow, producing a more stable and homogenous temperature distribution. As shown by the data reported in NEDE-21821, Section 4.3, stratification has been eliminated over the range of operating flows.

Flow hole cracks occurred partly because the surface of the hole was constrained by the in-plane stiffness of the surrounding sparger material when exposed to the exit flow to reactor coolant gradients, and partly because the gradients themselves were unstable. The instability of the gradients resulted from changing location of the separation point between the cold exit flow and the warmer boundary layer produced by heating of the sparger by reactor fluid. The result was a high-cycle thermal stress around the edge of the hole. This condition is eliminated at Grand Gulf by the exit flow elbows which have a long enough exit throat to stabilize the flow separation. Also, the thermal stress produced by a given gradient is much less with the exit hole in a cylindrical tube, rather than in what previously would behave locally more as a flat plate. Testing, as reported in NEDE-21821, Section 4.3, has shown that the high frequency thermal cycling is eliminated by the new design.

In order to allow for removal of the sparger, it is necessary to provide a sealed joint between the nozzle safe end and the thermal sleeve. This seal is achieved by use of a metal piston ring backed up with a coil spring expander. Even if the piston ring seal was leaktight when initially installed, its long-term sealing ability is unknown. The effects of wear and corrosion on the mating safe end surface would eventually cause leakage to increase to the point where nozzle cracking would initiate. The rate of deterioration is unpredictable, but is expected to be short relative to the life of the pressure vessel. To provide protection against seal failure resulting in nozzle cracking, the second piston ring and the added thermal sleeves have been incorporated in the new design for Grand Gulf. It has been demonstrated by test that the triple thermal sleeve arrangement prevents the leakage flow causing nozzle cracking. This is the result of the concentric sleeve arrangement channeling leakage away from the nozzle and the fact that the second seal is exposed to very low driving pressures, making leakage past it very small.

As mentioned earlier, the cracking of the feedwater nozzles is a two-part process. The crack initiation mechanism as discussed above is the result of self-initiated thermal cycling. If this were the only mechanism present, the cracks would initiate, grow to a depth of approximately 0.25 inch, and arrest. This degree of cracking could be tolerated, but unfortunately there is another mechanism which supports crack growth. This mechanism is the system-induced transients, primarily the startup/shutdown transients. The triple thermal sleeve arrangement also assists in this area because, even with the piston rings leaking, the heat transfer coefficient between the feedwater and the nozzle is reduced to the point where the thermal stresses in the nozzle are not high enough to cause significant crack growth. Analysis presented in NEDE-21821, Section 4.6, demonstrates this benefit and the benefit of using unclad nozzles on Grand Gulf.

The cracking of the CRD return nozzles is caused by a mechanism which is very similar to that which caused cracking in the feedwater nozzles, i.e., thermally induced fatigue.

The CRD return flow is always at a low temperature (40-140 F). The flow rate is also low and as the fluid passes through the nozzle it mixes with the hot (580 F) reactor coolant. This mixing is turbulent and results in alternating hot and cold cycling on the nozzle wall. The result is high cycle fatigue which initiates cracking. This mechanism has been demonstrated by test. Tests have also demonstrated that lower frequency thermal cycles occur in a stagnant CRD return line nozzle.

The fix implemented at Grand Gulf for this problem is the elimination of the CRD return line and the capping of the CRD return line nozzle. It has been shown that the CRD system will operate satisfactorily with the return line cut and capped. his has been demonstrated by tests at Peach Bottom, Fitzpatrick, and other operating BWRs and is allowed by NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Cracking," November 1980.

The design at Grand Gulf, as provided in this subsection, is in compliance with NUREG-0619. In addition, reports identified by NUREG-0619 were submitted in accordance with the instructions for implementation and acceptance identified in NUREG-0619. All necessary design changes required for compliance with the generic resolution of NUREG-0619 have been accomplished.

Stress analyses in keeping with the requirements of the ASME Code Section III have been performed to demonstrate the adequacy of the reactor vessel feedwater nozzle and the CRD return line nozzle cap.

The CRD hydraulic system return line nozzle and cap meet the requirements of the ASME Code, Section III, 1974 Edition, Paragraphs NB-3222.2, NB-3222.4, and NB-3223 (Ref. 1), including addenda through winter 1975, as a result of a stress and fatigue analysis for the cap and CRD hydraulic system return nozzle.

A stress analysis and a fatigue analysis were performed for the Grand Gulf RPV feedwater nozzle. The stress analysis showed compliance with Sub-article NB-3220 of the ASME Code, Section III (1971 Edition - winter addenda) for points outside the area of reinforcement (nozzle to shell junction) and with Paragraph NB-3331 for those points within the area of reinforcement. The fatigue analysis shows compliance with Paragraph NB-3332.4 of the ASME Code Section III as noted above.]

5.3.3.1.4.5.2 Examination of Feedwater Nozzles and Spargers

In addition to the evaluations described in 5.3.3.1.4.5.1, GGNS specific fracture mechanics analysis using inputs based on past and predicted operational performance has established the time required for a 0.250 inch flaw to grow to the maximum size permitted by ASME Section XI (critical flaw life). The original analysis is based on not exceeding 3 startup/shutdown events and 2 scram events per 18 month operating cycle. However, as operating time is accumulated, the analysis may be adjusted to either increase or decrease the critical flaw life based on the actual number of operating events. Each feedwater nozzle shall be ultrasonically examined (UT) in zones 1, 2, and 3 as shown in Figure 5.3-26. The examination frequency for zones 1 and 2 shall be 1/3 of the critical flaw life, not to exceed ten years, and zone 3 shall be examined at a frequency 2 times that required for zones 1 and 2. The examination schedule begins after all nozzles have completed a baseline examination with UT techniques and personnel that have been qualified as described below. The examination frequency shall be controlled by Program Section for ASME Section XI, Div. I Inservice Inspection Program.

The examination may be performed from the external surface of the RPV with either manual or automated techniques. The UT technique shall be demonstrated to acceptably detect and size flaws located on the entire inside surface of all 3 examination zones. An acceptable UT technique is one that has the ability to reliably detect radially oriented flaws with a depth equal to 0.250 inches for each of the zones. Depth sizing capabilities shall be demonstrated on a range of flaws in each zone. The depth sizing results may be statistically analyzed. The depth sizing criteria of ASME Section XI, Appendix VIII may be used. However, alternate methods of statistical analysis may be used provided that justification is included.

Technique qualification for detection and sizing need not be a blind test provided that the procedures contain definitive criteria. Furthermore, techniques demonstrated for use at one facility can be used at others provided applicability is technically supported through computer modeling for the different geometrical characteristics.

When UT techniques are qualified on a mockup without the use of modeling, the specimen thickness should be at least equal to the maximum thickness of the vessel nozzles to be examined, and the ratio of the nozzle thickness to shell thickness should be within ±30% of the ratio for the actual vessel nozzle to be examined.

Flaws in mockups for qualification shall be surface connected. Flaws may be notches and need not be cracks. The aspect ratio (depth to length) of the flaws shall be in the range of 0.1 to 0.5.

Modeling may be used to qualify the UT technique. One form of modeling is where the UT beam paths are predicted using ray tracing algorithms with predetermined beam angle parameters. The beam paths are used to determine the incident angles of the beam on the ID surfaces. Modeling should only be used for the qualification of UT techniques when acceptable incident beam angles have been previously determined by full scale mockup.

Personnel performing detection and sizing shall demonstrate their technical proficiency with qualified techniques on full scale mockups.

Sparger material, basic dimensions, and weld locations are presented in Figures 5.3-16 through 25. Descriptions of analyses and test data, projections, planned modifications and instrumentation are given in subsection 5.3.3.1.4.5.1.

5.3.3.1.4.5.3 Deleted

5.3.3.1.4.5.4 Acceptance Standards

Cracks will be measured and recorded, and record made of the circumferential and axial position of each crack.

The total depth of each crack will be determined. If any crack exceeds one-half inch, a safety analysis report, which includes a discussion of the proposed repair procedure, will be submitted to the NRC for review and approval prior to further action.

Recording and Reporting Standards

Inspection results will be communicated to the NRC as soon as practicable after results are obtained.

5.3.3.1.4.6 Materials and Inspections

The reactor vessel was designed and fabricated in accordance with the appropriate ASME Boiler and Pressure Vessel Code as defined in subsection 5.3.1. Table 5.2-4 defines the materials and specifications. Subsection 5.3.1.5.1 defines the compliance with reactor vessel material surveillance program requirements.

5.3.3.1.4.7 Reactor Vessel Schematic (BWR)

The reactor vessel schematic is contained in Figure 5.3-2. Trip system water levels are indicated as shown.

5.3.3.2 Materials of Construction

All materials used in the construction of the reactor pressure vessel conform to the requirements of ASME Code, Section II materials. The vessel heads, shells, flanges, and nozzles are fabricated from low alloy steel plate and forgings purchased in accordance with ASME specifications SA533 Grade B Class 1 and SA508 Class 2. Special requirements for the low alloy steel plate and forgings are discussed in subsection 5.3.1.2. Cladding employed on the interior surfaces of the vessel consists of austenitic stainless steel weld overlay.

These materials of construction were selected because they provide adequate strength, fracture toughness, fabricability, and compatibility with the BWR environment. Their suitability has been demonstrated by long term successful operating experience in reactor service.

5.3.3.3 Fabrication Methods

[HISTORICAL INFORMATION] [The reactor pressure vessel is a vertical, cylindrical pressure vessel of welded construction fabricated in accordance with ASME Code, Section III, Class 1 requirements. All fabrication of the reactor pressure vessel was performed in accordance with buyer-approved drawings, fabrication procedures, and test procedures. The shells and vessel heads were made from formed low alloy steel plates, and the flanges and nozzles from low alloy steel forgings. Welding performed to join these vessel components was in accordance with procedures qualified per ASME Code, Sections III and IX requirements. Weld test samples were required for each procedure for major vessel full penetration welds.

Submerged arc and manual stick electrode welding processes were employed. Electroslag welding was not permitted. Preheat and interpass temperatures employed for welding of low alloy steel met or exceeded the requirements of ASME Code, Section III, subsection NA. Post weld heat treatment of 1100 F minimum was applied to all low alloy steel welds.

All previous BWR pressure vessels have employed similar fabrication methods. These vessels have operated for periods up to 16 years and their service history is excellent.

The vessel fabricator, CBI Nuclear Co., has had extensive experience with GE reactor vessels and has been the primary supplier for GE domestic reactor vessels and some foreign vessels since the company was formed in 1972 from a merger agreement between Chicago Bridge and Iron Co. and GE. Prior experience by the Chicago Bridge and Iron Co. with GE reactor vessels dates back to 1966.]

5.3.3.4 Inspection Requirements

[HISTORICAL INFORMATION] [All plate, forgings, and bolting were 100 percent ultrasonically tested and surface examined by magnetic particle methods or liquid penetrant methods in accordance with ASME Code, Section III requirements. Welds on the reactor pressure vessel were examined in accordance with methods prescribed and met the acceptance requirements specified by ASME Code, Section III. In addition, the pressure retaining welds were ultrasonically examined using acceptance standards which were equivalent or more restrictive than required by ASME Code, Section XI.]

5.3.3.5 Shipment and Installation

[HISTORICAL INFORMATION] [The completed reactor vessel is given a thorough cleaning and examination prior to shipment. The vessel is tightly sealed for shipment to prevent entry of dirt or moisture. Preparations for shipment are in accordance with detailed written procedures. On arrival at the reactor site, the reactor vessel is carefully examined for evidence of any contamination as a result of damage to shipping covers. Suitable measures are taken during installation to assure that vessel integrity is maintained; for example, access controls are applied to personnel entering the vessel, weather protection is provided, periodic cleanings are performed, and only approved miscellaneous materials are used during assembly.]

5.3.3.6 Operating Conditions

Procedural controls on plant operation are implemented to hold thermal stresses within acceptable ranges. These restrictions on coolant temperature are controlled in accordance with the Technical Specifications.

The limit regarding the normal rate of heatup and cooldown (item a.) assures that the vessel closure, closure studs, vessel support skirt, and control rod drive housing stresses and usage remain within acceptable limits. The limit regarding a vessel temperature limit on recirculating pump operation and power level increase restriction (item b.) augments the item a. limit in further detail by assuring that the vessel bottom head region will not be warmed at an excessive rate caused by rapid sweep out of cold coolant in the vessel lower head region by recirculating pump operation or natural circulation (cold coolant can accumulate as a result of control drive inleakage and/or low recirculation flow rate during startup or hot standby). The item c. limit further restricts operation of the recirculating pumps to avoid high thermal stress effects in the pumps and piping, while also minimizing thermal stresses on the vessel nozzles.

The above operational limits when maintained ensure that the stress limits within the reactor vessel and its components are within the thermal limits to which the vessel was designed for normal operating conditions. To maintain the integrity of the vessel in the event that these operational limits are exceeded the reactor vessel has also been designed to withstand a limited number of transients caused by operator error. Also, for abnormal operating conditions where safety systems or controls provide an automatic temperature and pressure response in the reactor vessel, the reactor vessel integrity is maintained since the severest anticipated transients have been included in the design conditions. Therefore, it is concluded that the vessel integrity will be maintained during the most severe postulated transients, since all such transients are evaluated in the design of the reactor vessel. The postulated transient for which the vessel has been designed is shown on Figure 5.2-5 and discussed in subsection 5.2.2.

5.3.3.7 In-service Surveillance

In-service inspection of the reactor pressure vessel will be in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, as discussed in subsection 5.2.4.

The materials surveillance program will monitor changes in the fracture toughness properties of ferritic materials in the reactor vessel beltline region resulting from their exposure to neutron irradiation and thermal environment. Operating procedures will be modified in accordance with test results to ensure adequate brittle fracture control.

Material surveillance programs and in-service inspection programs are in accordance with applicable ASME Code requirements, and provide assurance that brittle fracture control and pressure vessel integrity will be maintained throughout the service lifetime of the reactor pressure vessel.

5.3.4 References

1. "An Analytical Study on Brittle Fracture of GE-BWR Vessel Subject to the Design Basis Accident" (NEDO-10029).

2. Deleted

3. Letter from W. H. Bateman (USNRC) to C. Terry (BWRVIP Chairman) titled, "Safety Evaluation Regarding EPRI Proprietary Reports "BWR Vessel and Internals Project - BWR Integrated Surveillance Program Plan (BWRVIP-78)' and 'BWRVIP-86: BWR Vessel and Internals Project, BWR Integrated Surveillance Program Implementation Plan" dated February 1, 2002.

4. Electric Power Research Institute (EPRI) Technical Report 1003346, entitled "BWRVIP-86-A: BWR Vessel and Internals project Integrated Surveillance Program (ISP) Implementation Plan," Final Report, dated October 2002.

5. Deleted

6. MPM-814779, Rev. 5, "Neutron Transport Analysis for Grand Gulf Nuclear Station," May 2015.

7. GGNS-NE-10-00073, Revision 1, Dated July 1, 2016, GGNS EPU - Pressure - Temperature Limits Report. This calculation is the basis for the Grand Gulf Nuclear Station Pressure and Temperature limits Report (PTLR),Upto 35 Effective Full-Power Years (EFPY) and 54 EFPY, Revision 1, contained in the Operating License (NPF-29) Manual.

8. Electric Power Research Institute (EPRI) Technical Report 1013400, entitled "BWRVIP-135, Revision 1: BWR Vessel and Internals Project Updated BWR Integrated Surveillance Program (ISP) Data Source Book and Plant Evaluations," Final Report dated June 2007.

9. Calculation No. MC-Q1B13-16001, Reactor Vessel Negative Pressure During Startup, Shutdown, and Off-Normal Conditions, Revision 0.

10. EPRI Letter GEXO-2014-00039 Advance Notification of New BWRVIP Integrated Surveillance Program (ISP) Data Applicable to Grand Gulf Nuclear Station, July 16, 2014.

GEH Nuclear energy, NEDC-33178P-A, Revision 1, GE Hitachi Nuclear Energy Methodology for Development of Reactor Vessel Pressure-Temperature Curves, June 2009.

TABLE 5.3-1: [HISTORICAL INFORMATION] GRAND GULF UNIT 1 BELTLINE PLATE TOUGHNESS DATA (SA-533 GRADE B, CLASS 1 PLATE - LUKENS STEEL CO.)

			Charpy V Notch Toughness (Top/Bottom)				
Plate	Heat #-Slab #	Dropweight NDT (Top/Bottom) F	Orientation (L or T)	Charpy Test Temp. F	Energy Ft-Lb	Lat. Expansion Mils	% Shear
#2 Shell							
22-1-3	C2594-2	0/-20	T	+60	50, 59, 69/ 52, 52, 51	43, 54, 45/ 48, 52, 48	40, 40, 40/ 50, 50, 50
			L	+60	80, 79, 87	68, 69, 63	60, 60, 60
			T	+40	38, 44, 42	42, 37, 39	30, 30, 30
			T	+60	52, 52, 51	48, 52, 48	50, 50, 50
			L	+40	55, 55, 55	47, 48, 47	50, 50, 50
			T	+212	96, 106, 105	78, 82, 81	99, 99, 99
				+70	63, 66, 69	55, 58, 59	50, 50, 50
				+60	60, 64, 65	55, 56, 55	50, 50, 50
				+40	67, 50, 50	56, 38, 38	40, 40, 40
				0	28, 16, 17	26, 17, 19	20, 20, 20
				-50	7, 11, 5	7, 13, 5	10, 10, 10
				-100	4, 3, 4	2, 4, 2	1, 1, 1
22-1-4	A1224-1*	-20/-20	T	+40	33, 48, 16/ 58, 61, 40	41, 32, 19/ 48, 37, 52	30, 30, 30/ 50, 50, 50
			L	+60	52, 74, 52/ 80, 69, 63	46, 49, 61/ 66, 64, 68	50, 50, 50/ 60, 60, 60
			T	+40	78, 68, 61/ 55, 51, 61	64, 40, 56/ 40, 52, 51	50, 50, 50/ 50, 50, 50
				+212	122, 117, 118	90, 91, 90	99, 99, 99
				+100	92, 97, 117	78, 85, 76	80, 80, 80

*This material is also in the reactor vessel surveillance program.

TABLE 5.3-1: [HISTORICAL INFORMATION] GRAND GULF UNIT 1 BELTLINE PLATE TOUGHNESS DATA (SA-533 GRADE B, CLASS 1 PLATE - LUKENS STEEL CO.) (Continued)

			Charpy V Notch Toughness (Top/Bottom)				
Plate	**Heat #- Slab #**	**Dropweight NDT (Top/Bottom) F**	**Orientation (L or T)**	**Charpy Test Temp. F**	**Energy Ft-Lb**	**Lat. Expansion Mils**	**% Shear**
#2 Shell							
				+70	62, 61, 59	59, 62, 54	60, 60, 60
				+50	56, 50, 61	53, 44, 50	50, 50, 50
				+10	37, 35, 47	32, 41, 35	30, 30, 30
				-20	38, 37, 33	29, 31, 31	20, 20, 20
				-70	10, 9, 3	9, 7, 11	1, 1, 1
22-1-1	C2593-2	-50/-30	T	+10	57, 30, 48	45, 40, 39	40, 40, 40
			L	+10	92, 96, 93	70, 71, 70	70, 70, 70
			T	+20	52, 60, 61	47, 51, 48	50, 50, 50
			T	+30	61, 61, 65	50, 50, 53	50, 50, 50
			L	+30	81, 79, 73	63, 65, 66	70, 70, 70
			T	+212	102, 104, 100	76, 76, 79	99, 99, 99
				+70	89, 63, 84	56, 71, 72	70, 70, 70
				+30	87, 58, 77	61, 70, 51	60, 60, 60
				0	46, 36, 42	33, 37, 39	30, 30, 30
				-50	18, 36, 42	17, 29, 31	20, 20, 20
				-100	13, 4, 7	2, 9, 5	1, 1, 1
22-1-2	C2594-1	-10/-30	T	+50	56, 50, 62	48, 43, 53	40, 40, 40
			L	+50	69, 71, 68	57, 62, 60	50, 50, 50
			T	+30	53, 86, 60	63, 47, 49	50, 50, 50
			L	+30	75, 79, 68	69, 71, 68	70, 70, 70
			T	+212	108, 94, 98	79, 76, 76	99, 99, 99

TABLE 5.3-1: [HISTORICAL INFORMATION] GRAND GULF UNIT 1 BELTLINE PLATE TOUGHNESS DATA (SA-533 GRADE B, CLASS 1 PLATE - LUKENS STEEL CO.) (Continued)

			Charpy V Notch Toughness (Top/Bottom)				
Plate	Heat #- Slab #	Dropweight NDT (Top/Bottom) F	Orientation (L or T)	Charpy Test Temp. F	Energy Ft-Lb	Lat. Expansion Mils	% Shear
#2 Shell							
				+150	90, 96, 99	77, 80, 74	90, 90, 90
				+70	85, 61, 75	51, 62, 63	70, 70, 70
				0	51, 55, 37	44, 36, 49	40, 40, 40
				-10	37, 36, 39	35, 33, 31	30, 30, 30
				-30	23,31, 20	19, 23, 28	30, 30, 30
				-50	20, 23, 11	16, 11, 8	10, 10, 10

TABLE 5.3-2: [HISTORICAL INFORMATION] GRAND GULF UNIT 1 BELTLINE PLATE TOUGHNESS DATA (POST WELD 1150 F FOR 50 HOURS TYPICAL)

					Charpy V Notch Toughness			
Weld Seam	**Type**	**Heat #**	**Lot # or Flux #**	**Drop-Weight NDT F**	**Charpy Temp,F**	**Charpy Energy Ft-Lbs**	**Lateral Expansion Mils**	**% Shear**
#2 Shell Longitudinal Seams	E8018-G* (Trade Name Atom Arc 8018 NM)	627260	B322A27AE	-40	-40	23, 10, 16	15, 5, 11	5, 5, 5
					-10	23, 22	15, 15	15, 15
					+20	48, 56	31,36	20, 30
					+30	52, 56, 51	36, 37, 35	30, 35, 45
					+40	51, 55	30,37	25, 35
					+70	83, 65	55,40	75, 65
					+100	101, 95	70,67	95, 95
					+150	115, 108, 104	75, 74, 71	100, 100, 100
	E8018-G* Trade Name Atom Arc 8018 NM)	626677	C301A27AF	-40	-70	10, 13	8, 12	0, 0
					-40	17, 20, 27	15, 17, 20	5, 5, 5
					-20	27, 29	24, 26	10, 10
					0	43, 22	33, 21	20, 15
					+40	53, 51, 54	36, 37, 35	25, 25, 25
					+70	66, 70	54, 46	75, 75
					+100	83, 89	61, 69	90, 95
					+150	90, 92, 102	74, 61, 78	100, 100, 100

TABLE 5.3-2: [HISTORICAL INFORMATION] GRAND GULF UNIT 1 BELTLINE PLATE TOUGHNESS DATA (POST WELD 1150 F FOR 50 HOURS TYPICAL) (Continued)

					Charpy V Notch Toughness			
Weld Seam	**Type**	**Heat #**	**Lot # or Flux #**	**Drop-Weight NDT F**	**Charpy Temp,F**	**Charpy Energy Ft-Lbs**	**Lateral Expansion Mils**	**% Shear**
	INMM** (Single Wire, Trade Name Raco)	5P6214B	0331 (Linde 124)	-50	-70	22, 13, 11	17, 10, 9	2, 2, 2
					-50	42, 13, 34	34,11, 26	15, 5, 10
					+10	56, 50, 54	45, 41, 46	25, 20, 30
					+40	76, 66	66, 52	75, 45
					+100	87, 89	70, 64	95, 90
					+120	96, 90, 88	68, 61, 71	100, 100, 100
	E8018-G* (Trade Name Atom Arc 8018NM)	627069	C31A27AG	-60	-80	9, 8	6, 5	2, 2
					-60	28, 27, 30	26, 24, 25	5, 5, 5
					0	72, 64, 78	52, 48, 56	35, 35, 45
					+40	68, 86	56, 69	40, 75
					+100	117, 107	74, 89	95, 90
					+150	114, 117, 112	73, 64, 73	100, 100, 100

TABLE 5.3-2: [HISTORICAL INFORMATION] GRAND GULF UNIT 1 BELTLINE PLATE TOUGHNESS DATA (POST WELD 1150 F FOR 50 HOURS TYPICAL) (Continued)

					Charpy V Notch Toughness			
Weld Seam	**Type**	**Heat #**	**Lot # or Flux #**	**Drop-Weight NDT F**	**Charpy Temp,F**	**Charpy Energy Ft-Lbs**	**Lateral Expansion Mils**	**% Shear**
	E8018-G* (Trade Name Atom Arc 8018NM)	422K8511	G313A27AD	-80	-90	14, 17	15, 16	5, 5
					-80	14, 16, 20	15, 16, 20	10, 10, 10
					-40	26, 26, 40	26, 24, 33	30, 30, 30
					-20	65, 74, 127	44, 48, 76	40, 50, 60
					+25	107, 108	74, 80	80, 70
					+40	125, 125, 140	84, 89, 82	100, 100, 90
					+50	153, 143, 156	95, 81, 91	90, 80, 90
					+68	153, 143, 165	85, 96, 91	100, 100, 100

* Shielded Metal Arc Weld
** Submerged Arc Weld

NOTE: Weld materials 627260, 626677, and 5P6214B are in the reactor vessel surveillance program.

TABLE 5.3-3: Deleted

TABLE 5.3-3a: Deleted

1.

TABLE 5.3-3b: Deleted

TABLE 5.3-3c: Deleted

TABLE 5.3-3d: Deleted

3.

TABLE 5.3-3e: Deleted

4.

TABLE 5.3-3f: Deleted

TABLE 5.3-4: Deleted

TABLE 5.3-5: Deleted

TABLE 5.3-6: [HISTORICAL INFORMATION] GRAND GULF UNIT 1 VESSEL BELTLINE PLATES

Plate	Cu	P	C	Mn	Si	S	Ni	Mo	V
C2593-2	.04	.012	.19	1.22	.20	.015	.59	.55	NA
C2594-1	.04	.012	.20	1.24	.21	.012	.63	.56	NA
C2594-2	.04	.012	.20	1.24	.21	.012	.63	.56	NA
A1224-1	.04	.007	.18	1.32	.26	.014	.65	.55	NA

VESSEL BELTLINE LONGITUDINAL WELD MATERIAL

Weld	Cu	P	C	Mn	Si	S	Ni	Mo	V
5P6214B	.02	.013	NA	NA	NA	NA	.82	NA	NA
627260	.06	.020	NA	NA	NA	NA	1.08	NA	NA
626677	.03	NA	NA	NA	NA	NA	1.04	NA	NA
627069	.03	NA	NA	NA	NA	NA	1.04	NA	NA
422K8511	.01	NA	NA	NA	NA	NA	1.00	NA	NA

TABLE 5.3-7: Deleted

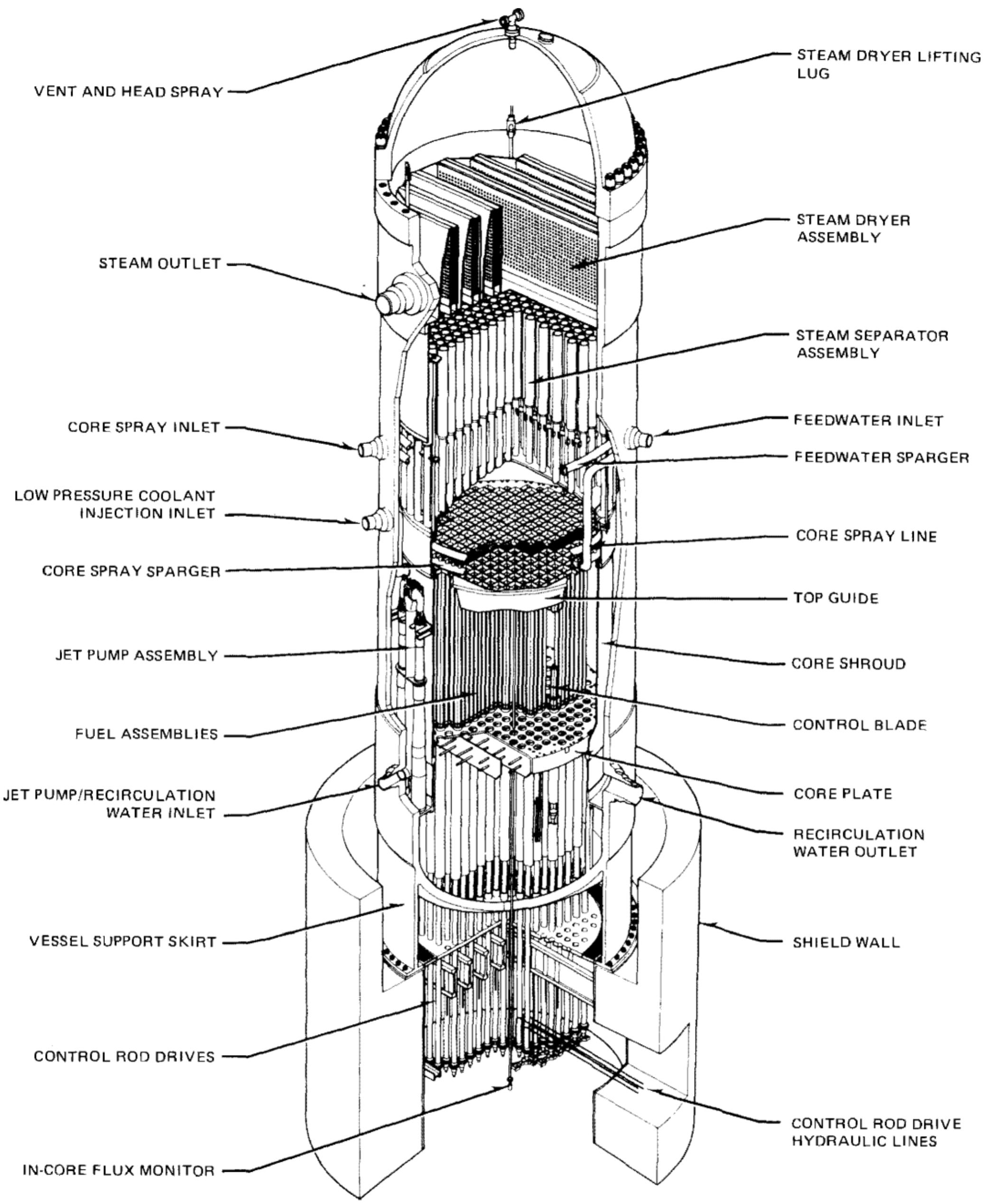
TABLE 5.3-8: MATERIALS DATA OF COMPONENTS OF FEEDWATER OUTBOARD CONTAINMENT ISOLATION VALVE

Valve Component	Thickness	Material	Heat Treatment*	Physical Tests	Heat Number
Body	2 19/64"	SA-352 Gr. LCB	1200 F ± 25 F PWHT	Yield- 61,500 psi Tensile- 81,500 psi Elong.- 30% Reduction of Area - 62.7%	F8063
Cover	5”	SA-350 Gr. LF-2	1650 F @ 6 hr Air Cooled	Yield - 44,000 psi Ultimate Tensile - 77,500 psi Elong. - 32% Reduction of Area - 60.5%	214903
Disc**	4”	SA-352 Gr. LCB	1200 F ± 25 F PWHT	Yield - 66,000 psi Tensile - 90,000 psi Elong. - 28% Reduction of Area - 61.5%	F8095

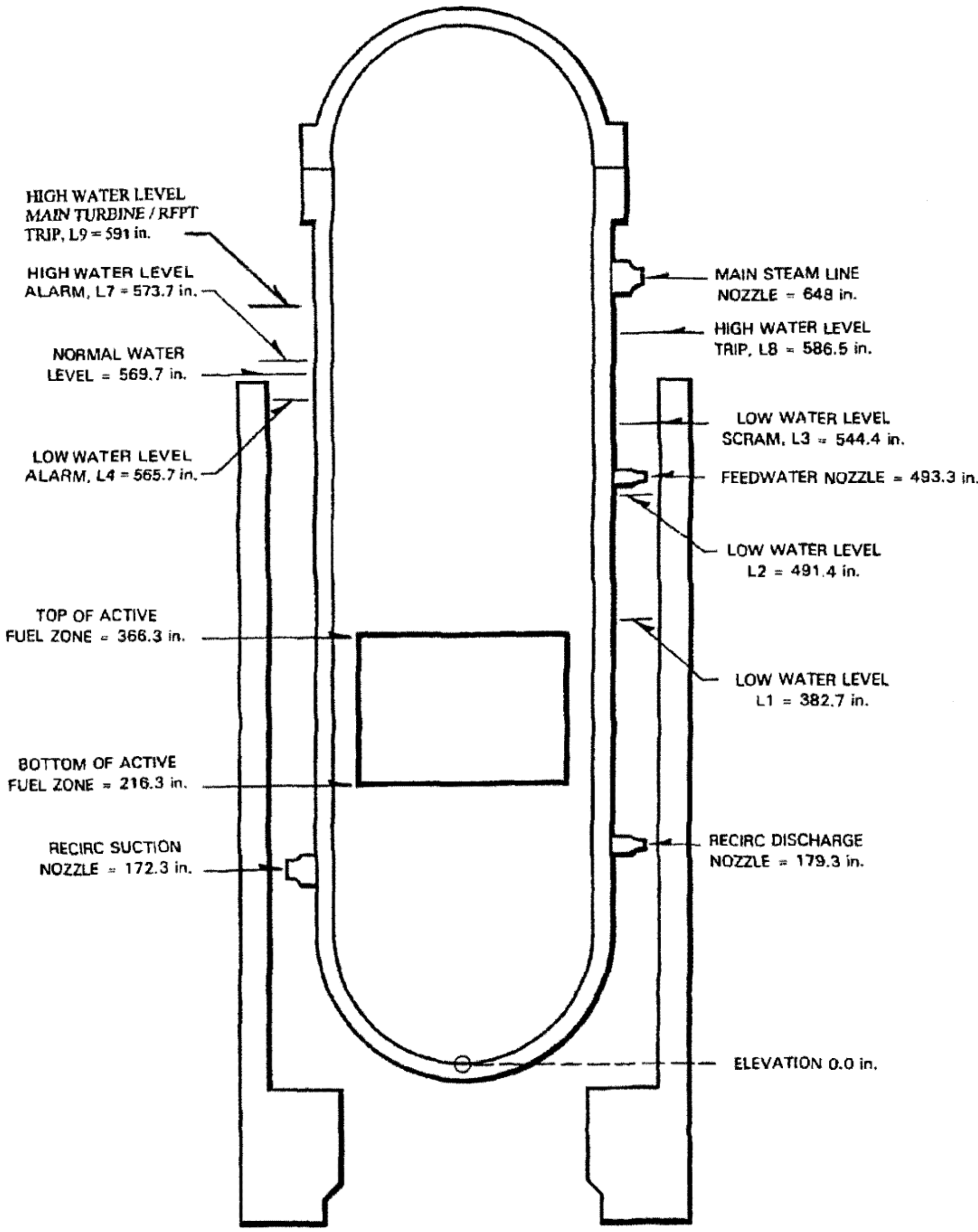
* A full description of the heat treatment was submitted via separate letter, L. F. Dale, MP&L, to H. R. Denton, NRC, dated August 21, 1981.

** This disc material is only applicable for the Q1B21F032A valve. The disc material is being changed to austenitic stainless steel for Q1B21F032B and is exempt from impact testing per ASME Code, Section III, NB-2311(6). This replacement disc will be installed prior to the first refueling outage.

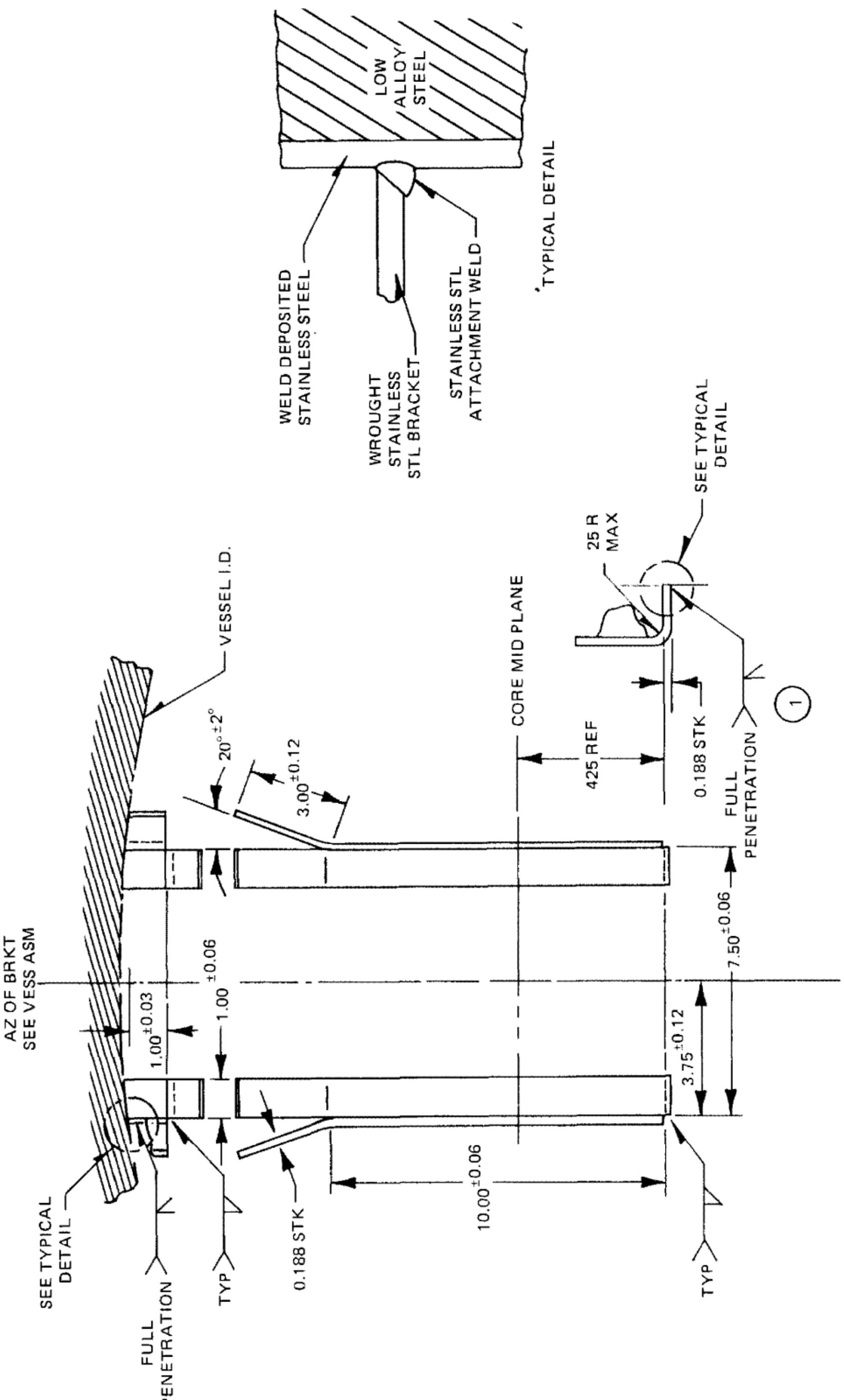
TABLE 5.3-9: Deleted



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	REACTOR VESSEL CUT-A-WAY DIAGRAM FIGURE 5.3-1

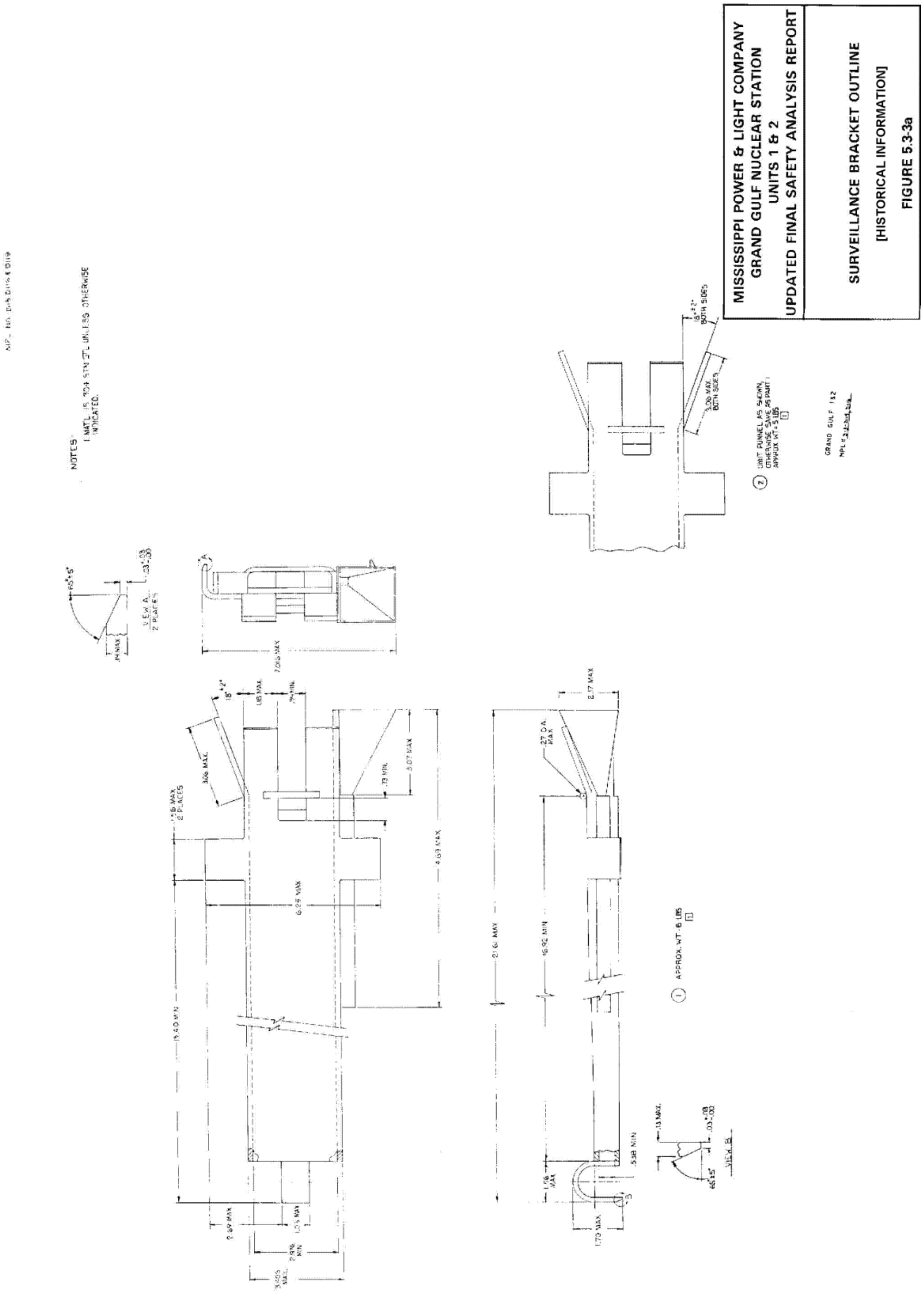


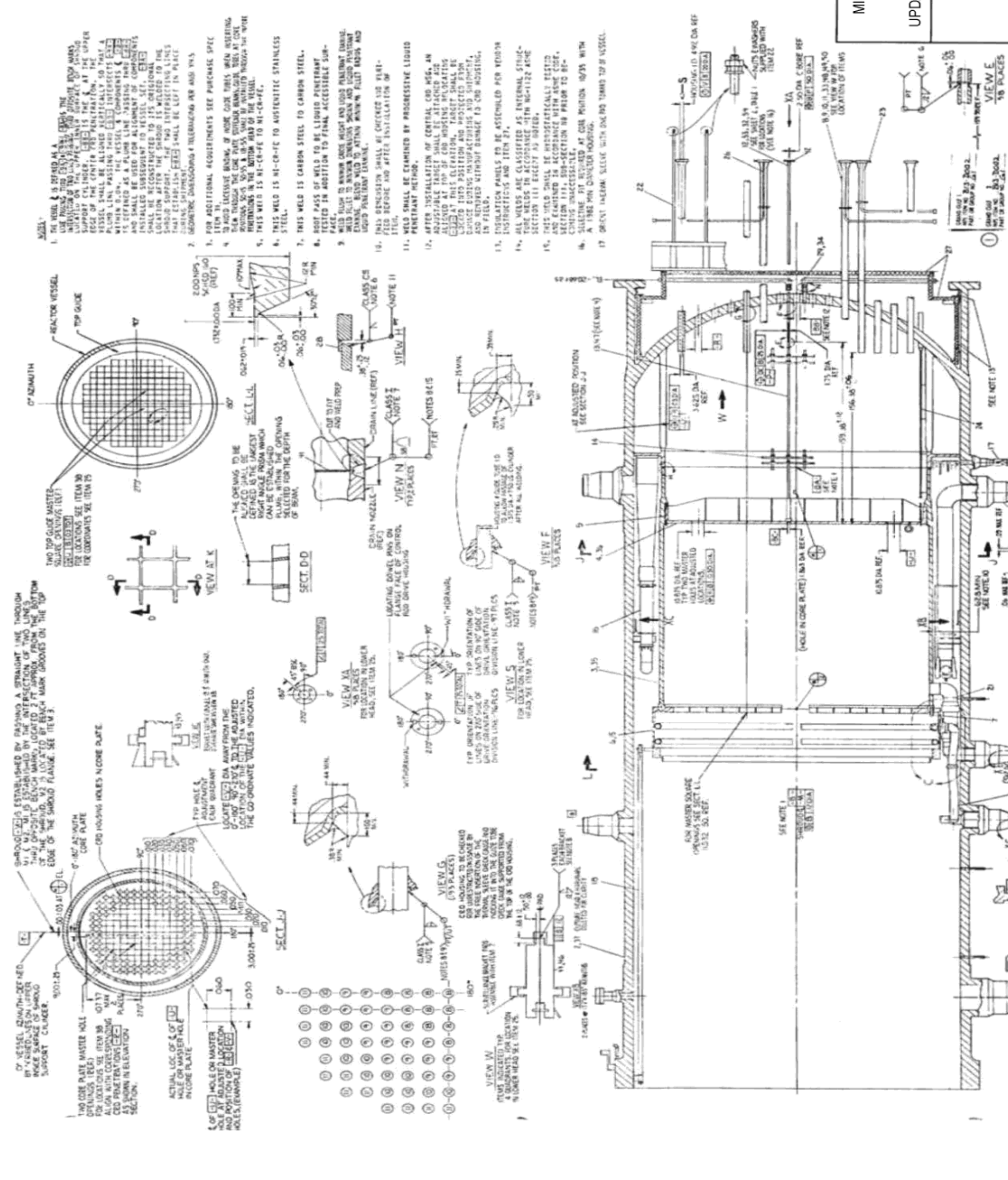
GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	NOMINAL REACTOR VESSEL WATER LEVEL TRIP AND ALARM ELEVATION SETTINGS FIGURE 5.3-2



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

BRACKET FOR HOLDING SURVEILLANCE CAPSULE
FIGURE 5.3-3
[HISTORICAL INFORMATION]


MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT
SURVEILLANCE BRACKET OUTLINE
[HISTORICAL INFORMATION]
FIGURE 5.3-3a



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

VESSEL AND COMPONENTS
[HISTORICAL INFORMATION]

FIGURE 5.3-3B

Rev. 0

Figure 5.3-4 is deleted.
(replaced by Figures 5.3-4-1 thru 5.3-4-5)

FIGURE 5.3-4-1 DELETED

FIGURE 5.3-4-2 DELETED

FIGURE 5.3-4-3 DELETED

FIGURE 5.3-4-4 DELETED

FIGURE 5.3-4-5 DELETED

FIGURE 5.3-4a DELETED

Figure 5.3-5 is deleted.

Figure 5.3-6 is deleted.

Figure 5.3-7 is deleted.

FIGURE 5.3-8 DELETED

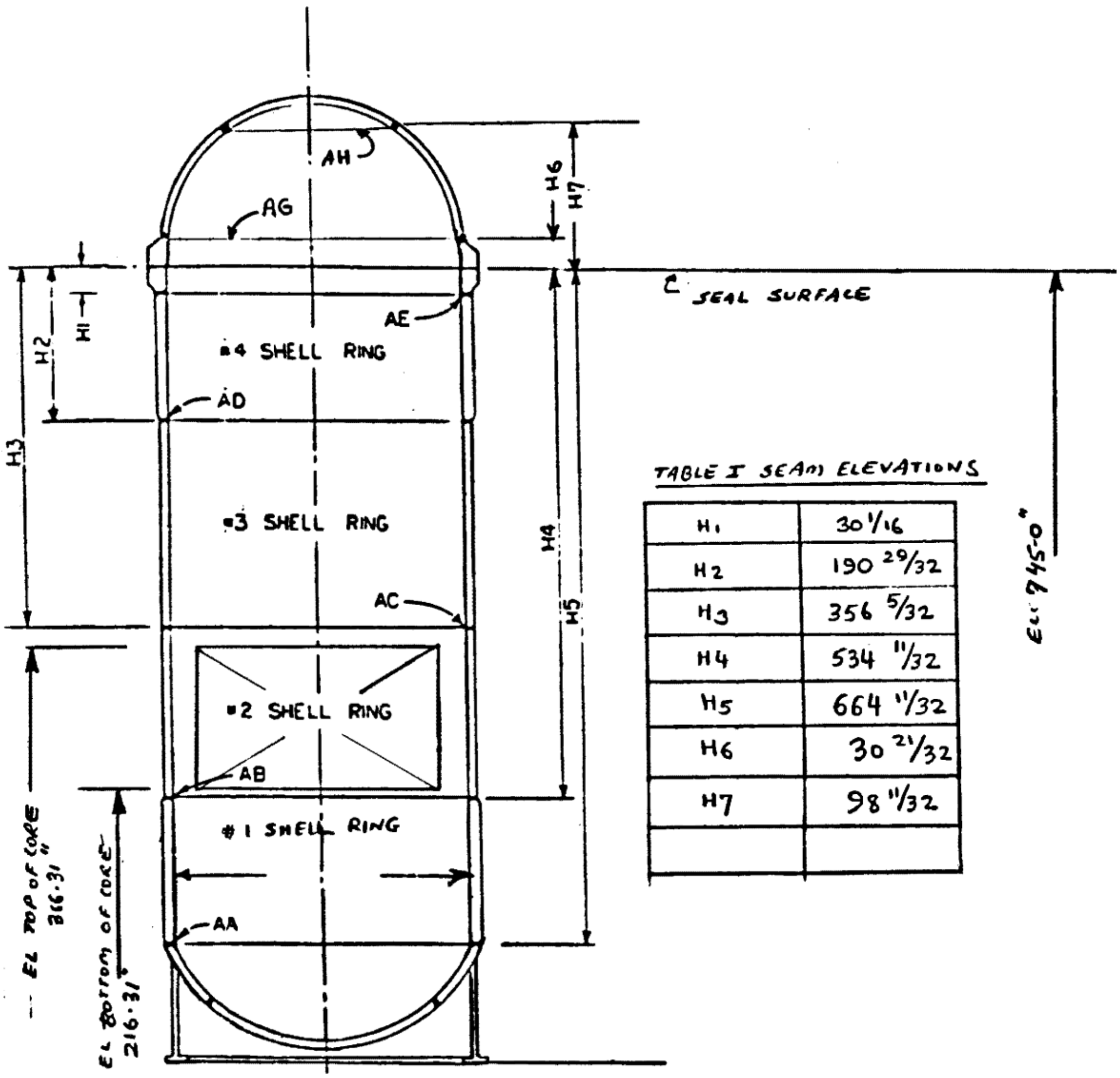


TABLE I SEAM ELEVATIONS

H1	30 1/16
H2	190 29/32
H3	356 5/32
H4	534 11/32
H5	664 11/32
H6	30 21/32
H7	98 11/32

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SECTION THROUGH VESSEL ASSEMBLY

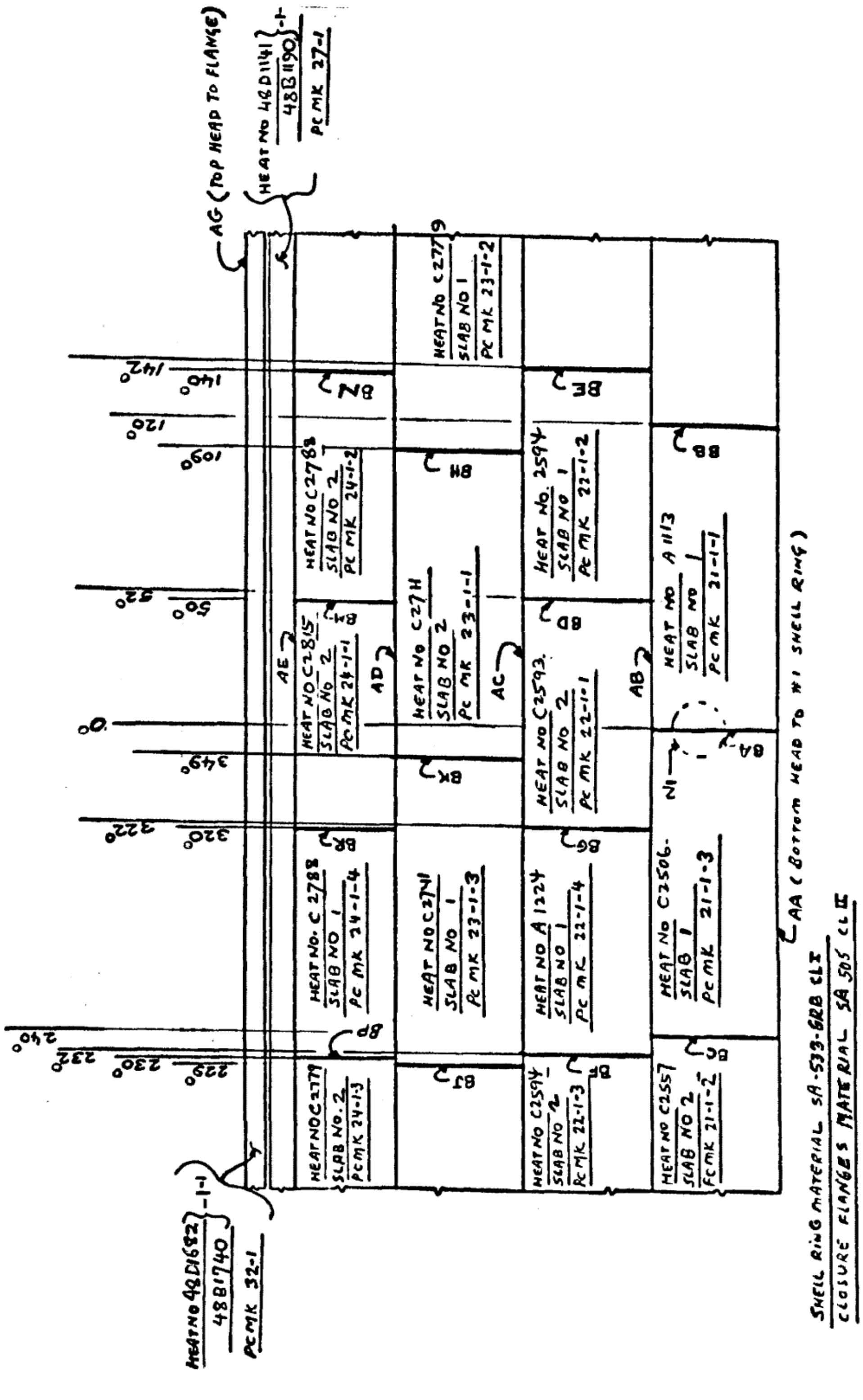
[HISTORICAL INFORMATION]

FIGURE 5.3-9

Figure 5.3-10
Deleted

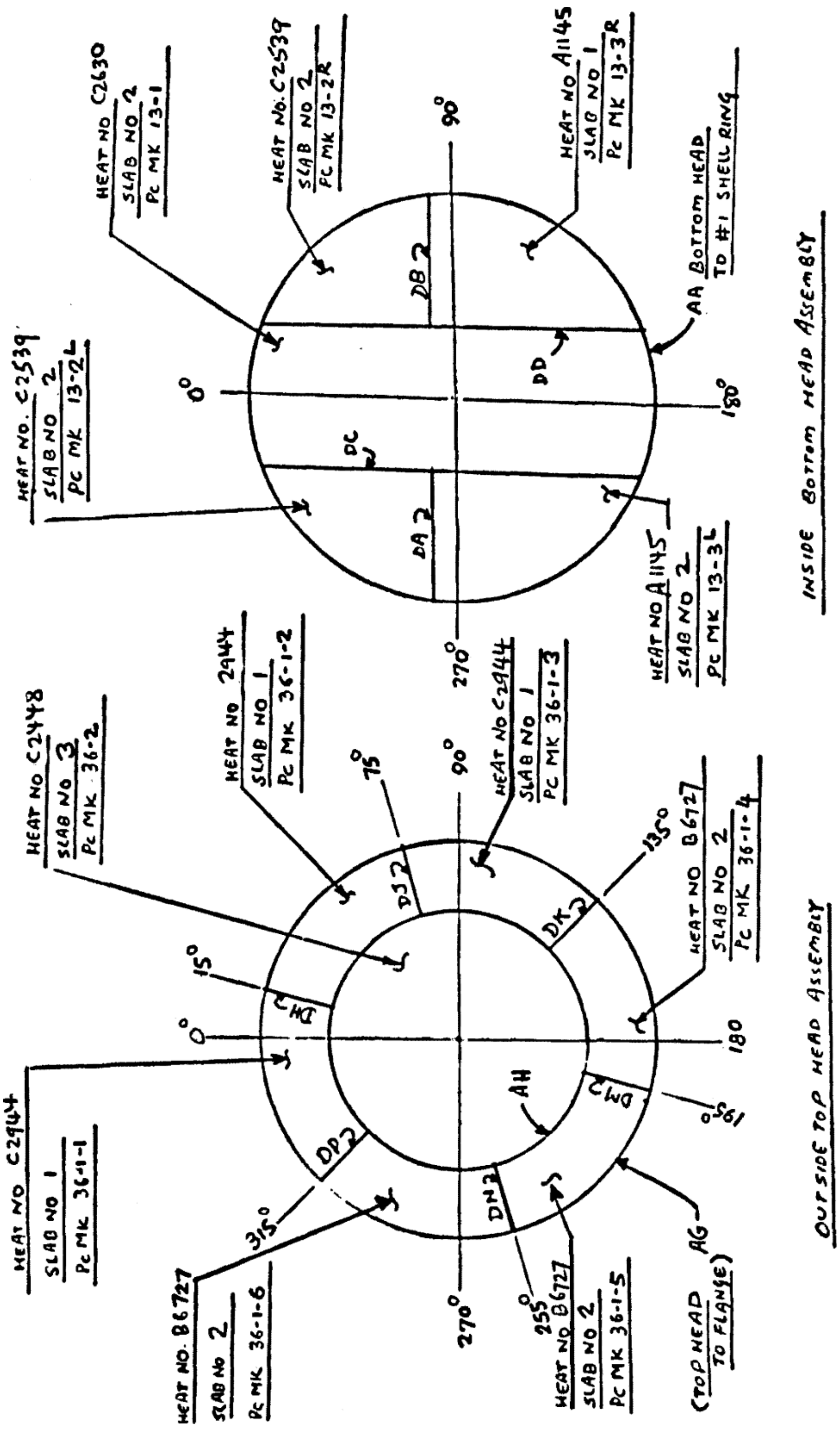
Figure 5.3-11
Deleted

Figure 5.3-12
Deleted



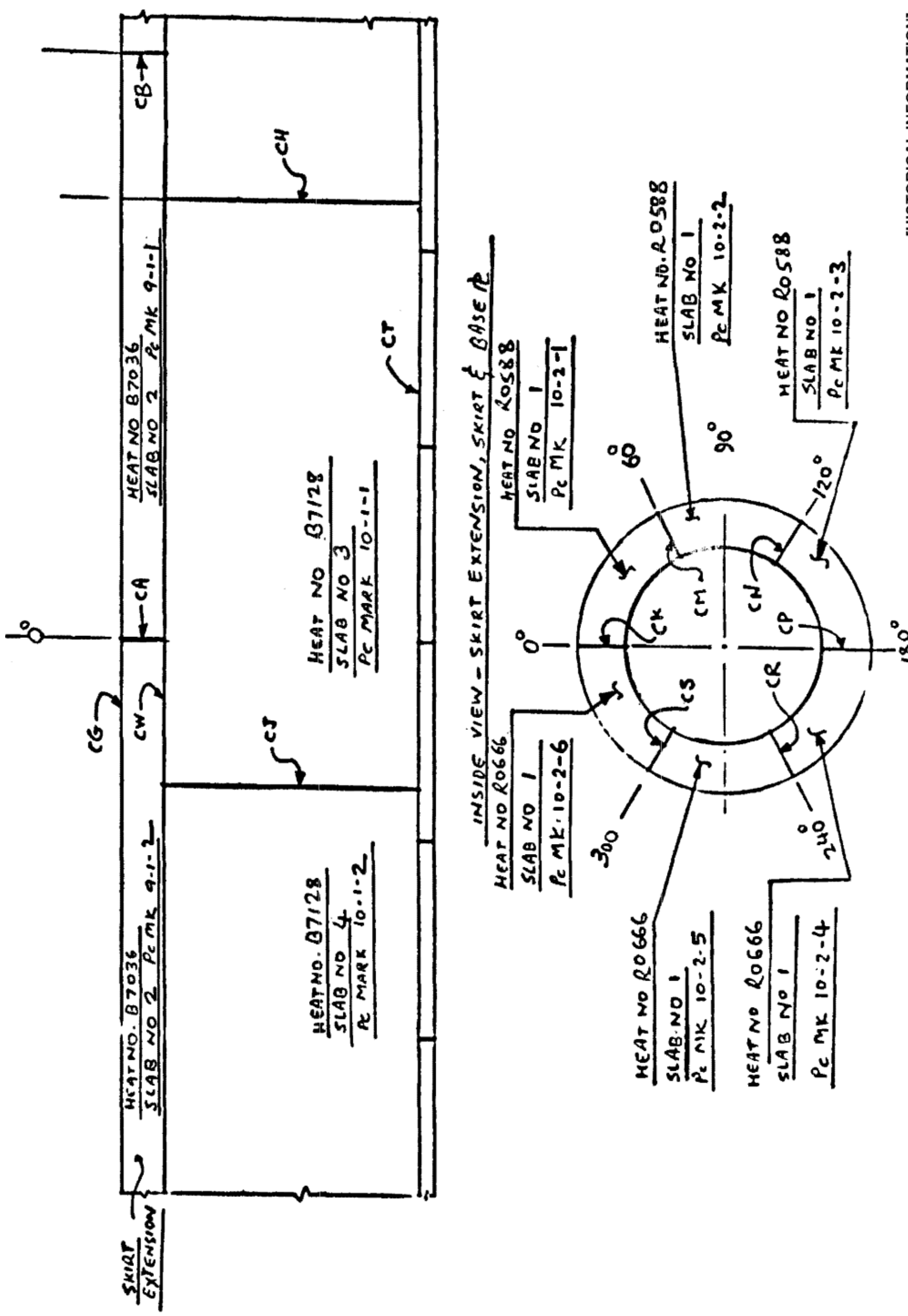
SHELL RING ASSEMBLIES & FLANGES
WELD SEAMS & PLATE IDENTIFICATION
[HISTORICAL INFORMATION]
FIGURE 5.3-13

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

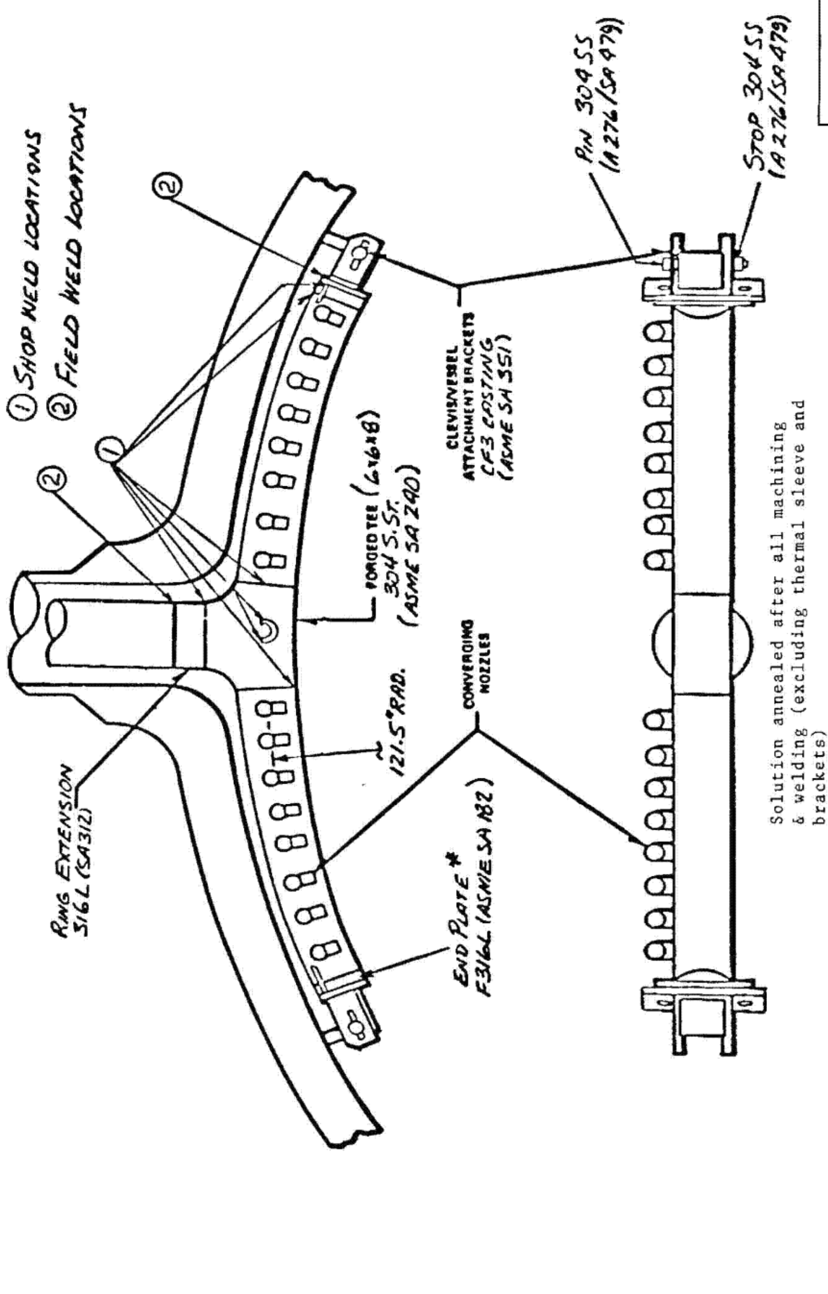
OUTSIDE TOP HEAD AND
INSIDE BOTTOM HEAD ASSEMBLIES
[HISTORICAL INFORMATION]
FIGURE 5.3-14



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

INSIDE VIEW
SKIRT EXTENSION, SKIRT
AND BASEPLATE
FIGURE 5.3-15



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

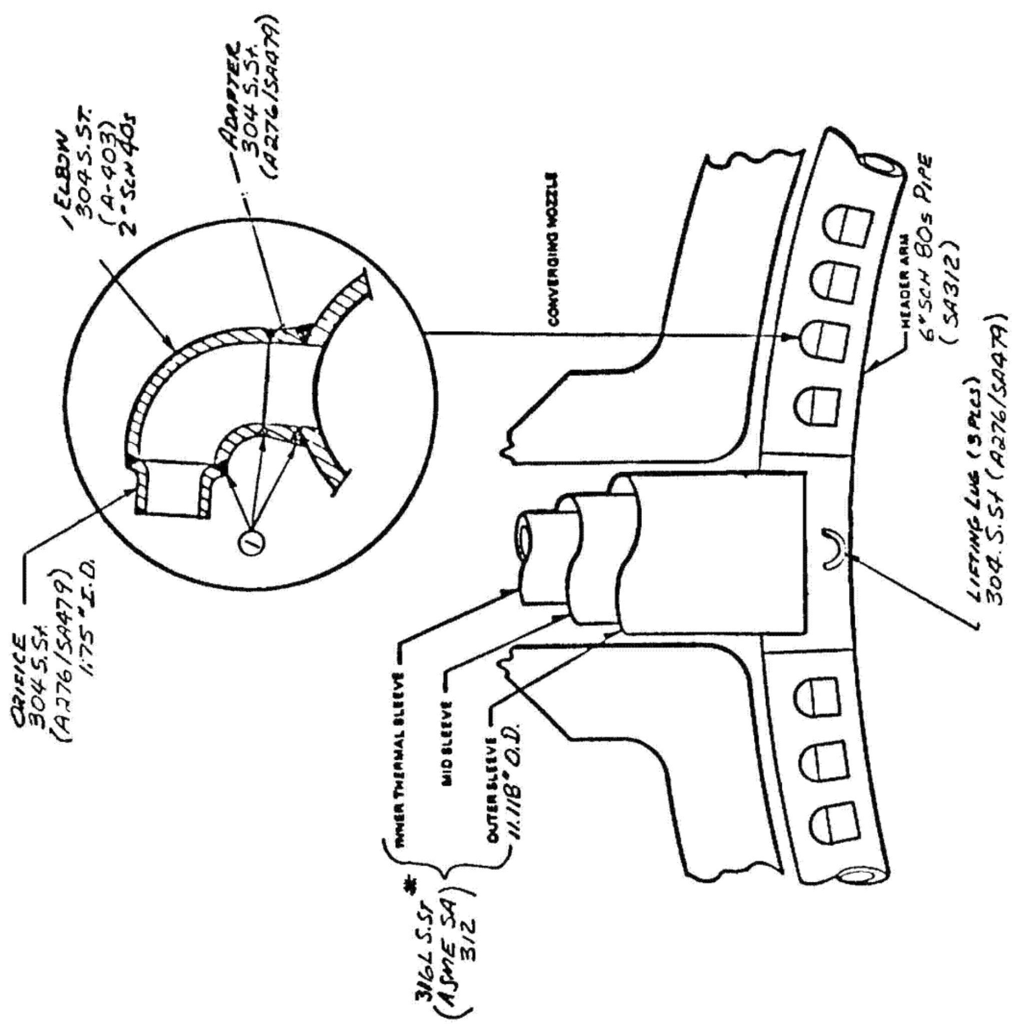
IMPROVED INTERFERENCE FIT FEEDWATER SPARGER ASSEMBLY

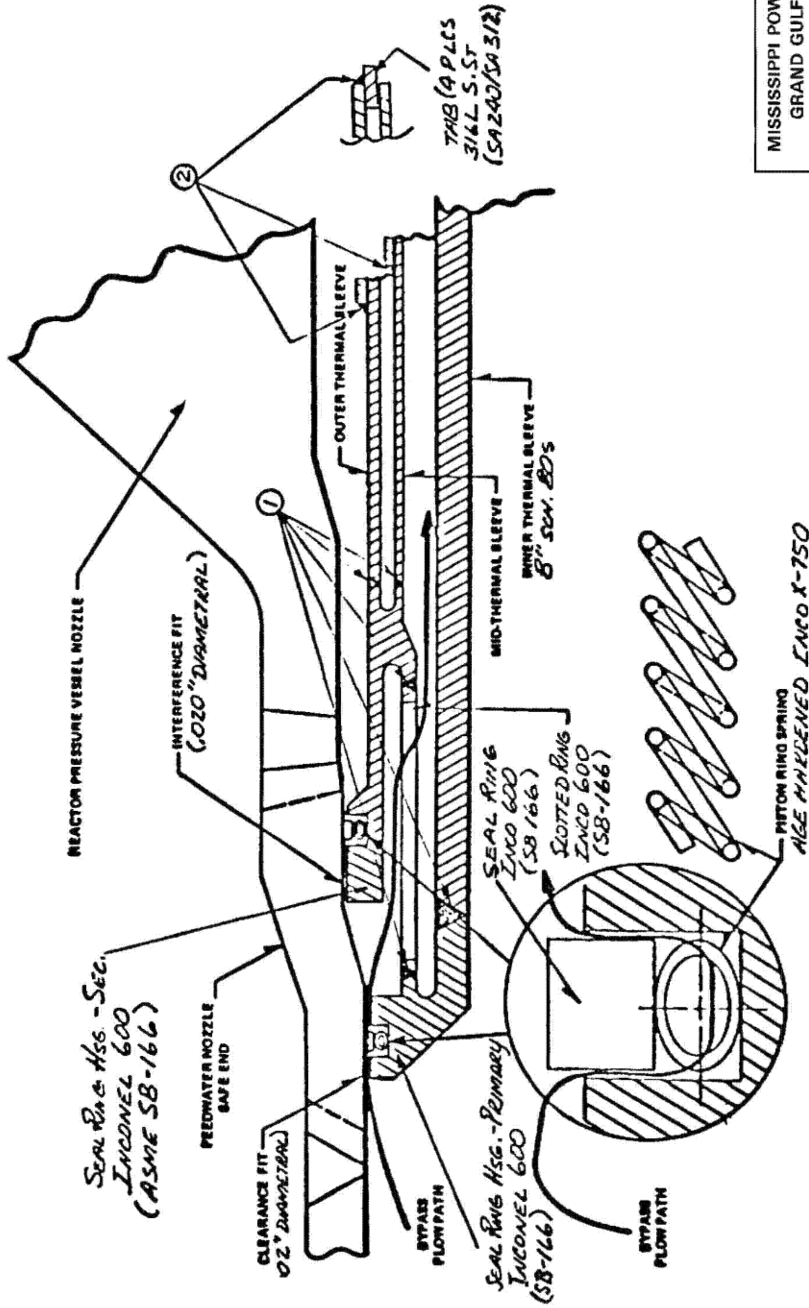
FIGURE 5.3-16

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

IMPROVED INTERFERENCE FIT
FEEDWATER SPARGER ASSEMBLY
NOZZLE & THERMAL SLEEVE
ARRANGEMENT

FIGURE 5.3-17

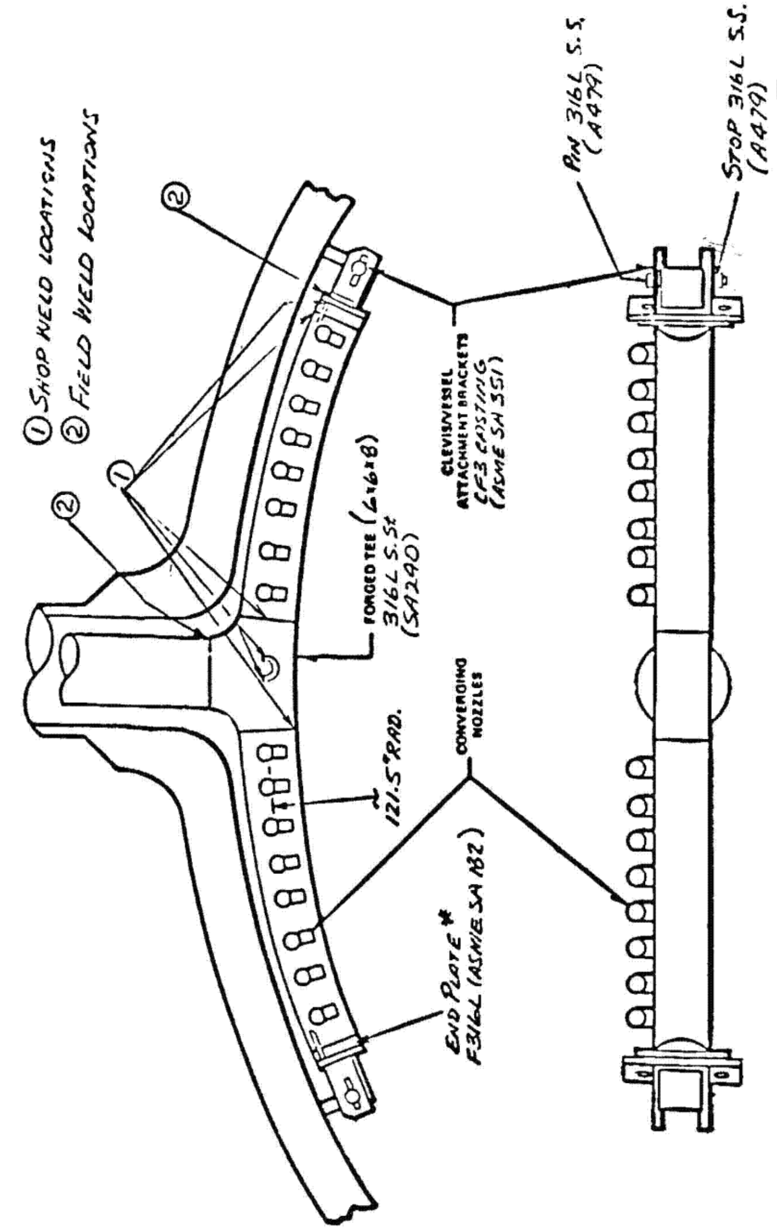




MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

IMPROVED INTERFERENCE FIT
FEEDWATER SPARGER
THERMAL SLEEVE INTERFERENCE
FIT DERMIS

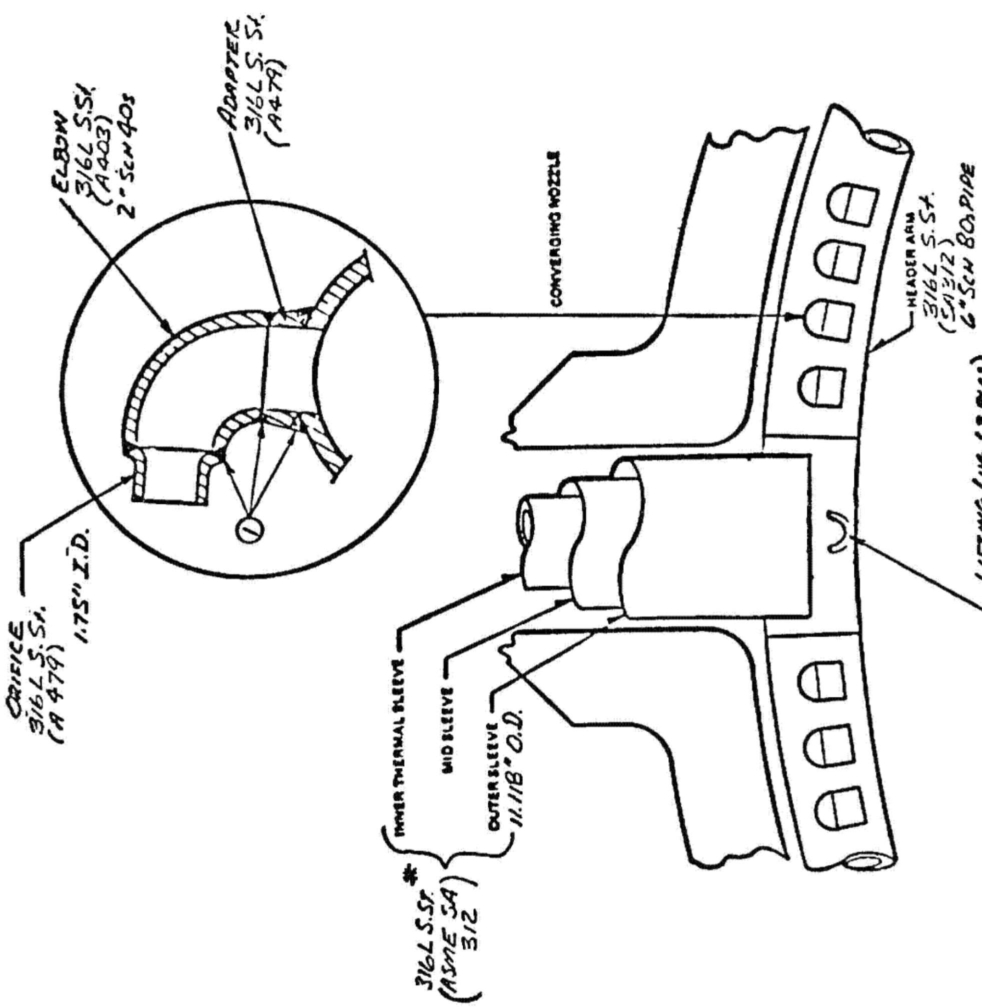
FIGURE 5.3-18



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

IMPROVED INTERFERENCE FIT FEEDWATER SPARGER ASSEMBLY

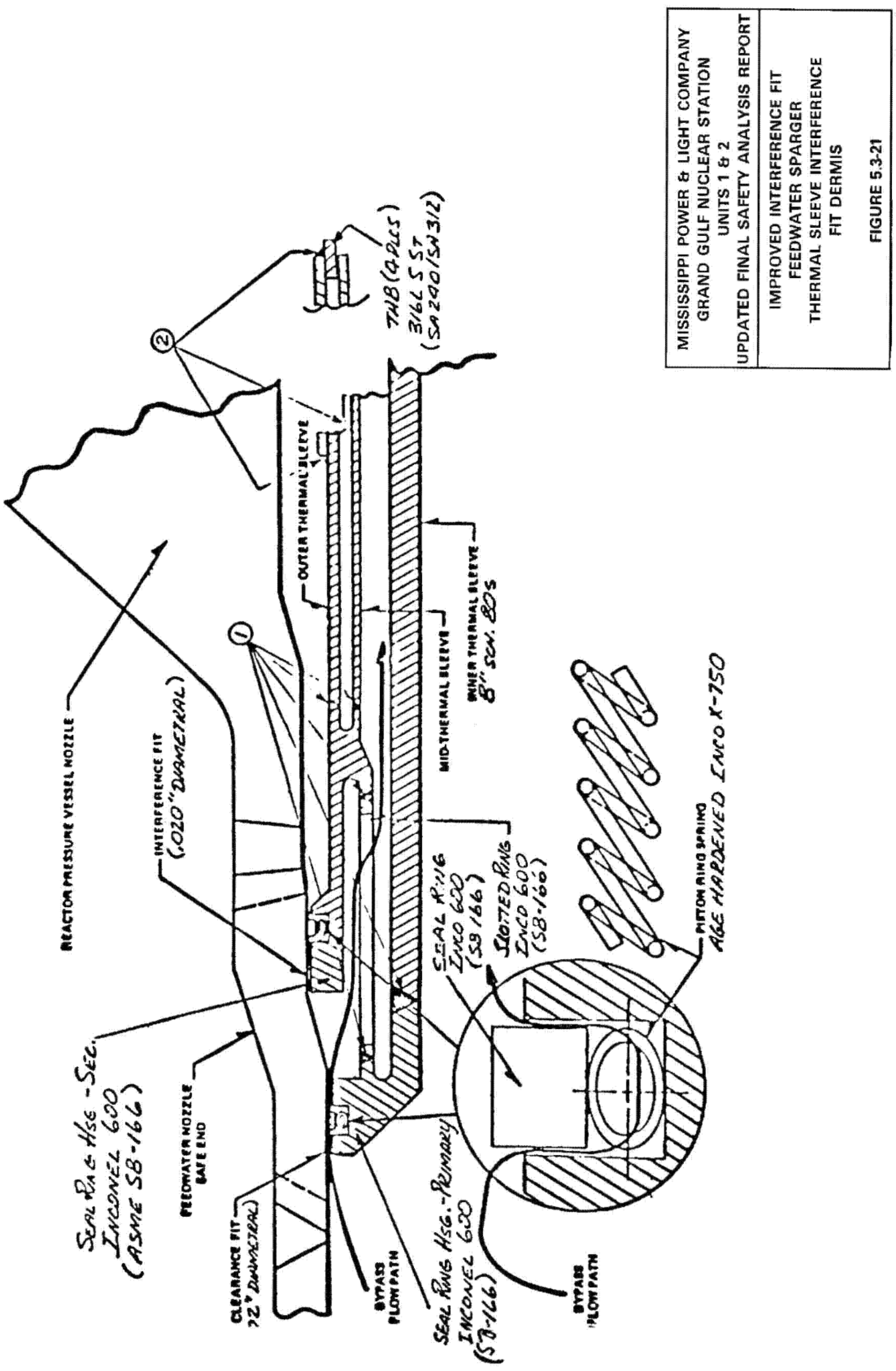
FIGURE 5.3-19

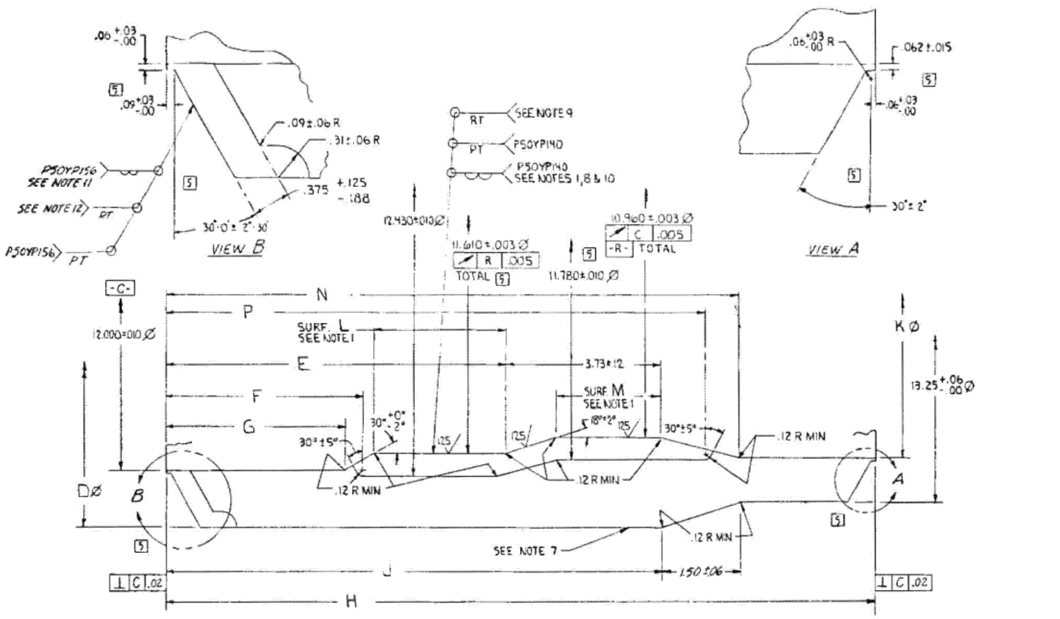


MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

IMPROVED INTERFERENCE FIT
FEEDWATER SPARGER ASSEMBLY
NOZZLE & THERMAL SLEEVE
ARRANGEMENT

FIGURE 5.3-20


MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT
IMPROVED INTERFERENCE FIT
FEEDWATER SPARGER
THERMAL SLEEVE INTERFERENCE
FIT DERMIS
FIGURE 5.3-21
REACTOR PRESSURE VESSEL NOZZLE
INTERFERENCE FIT
(.020" DIAMETRAL)
OUTER THERMAL SLEEVE
MID-THERMAL SLEEVE
INNER THERMAL SLEEVE
8" SCH. 80S
THB (4 PLCS)
316L S ST
(SA240/SA312)
FEEDWATER NOZZLE
SAFE END
CLEARANCE FIT
.72" DIAMETRAL
BYPASS
FLOW PATH
SEAL RING HSG - SEC.
INCONEL 600
(ASME SB-166)
SEAL RING HSG. - PRIMARY
INCONEL 600
(SB-166)
SEAL RING
INCO 600
(SB 166)
SLOTTED RING
INCO 600
(SB-166)
PISTON RING SPRING
AGE HARDENED INCO X-750



MAKE FROM 137C5285P15

PART NO.	N±.13	P±.19	D+.06 -.00	E+.06 -.00	F±.06	G±.03	H±.06	J±.06	K±.010
1	11.31	10.69	14.25	6.50	3.86	3.50	13.60	9.80	11.507
2	11.31	10.69	14.25	6.50	3.86	3.50	13.60	9.80	11.507
3	11.31	10.69	14.25	6.50	3.86	3.50	13.60	9.80	11.507
4	11.31	10.69	14.13	6.50	3.86	3.50	13.60	9.80	11.507
5	10.81	10.19	14.25	6.00	3.36	3.00	13.10	9.30	11.507
6	11.31	10.69	14.25	6.50	3.86	3.50	13.60	9.80	11.507
7	10.81	10.19	14.25	6.00	3.36	3.00	13.10	9.30	11.234
8	10.81	10.19	14.25	6.00	3.36	3.00	13.10	9.30	11.507
9	11.31	10.69	14.25	6.50	3.86	3.50	13.60	9.80	11.507

ESSENTIAL COMPONENT
THIS ITEM IS OR CONTAINS A SAFETY RELATED COMPONENT
ASME CODE SECTION III, CLASS I

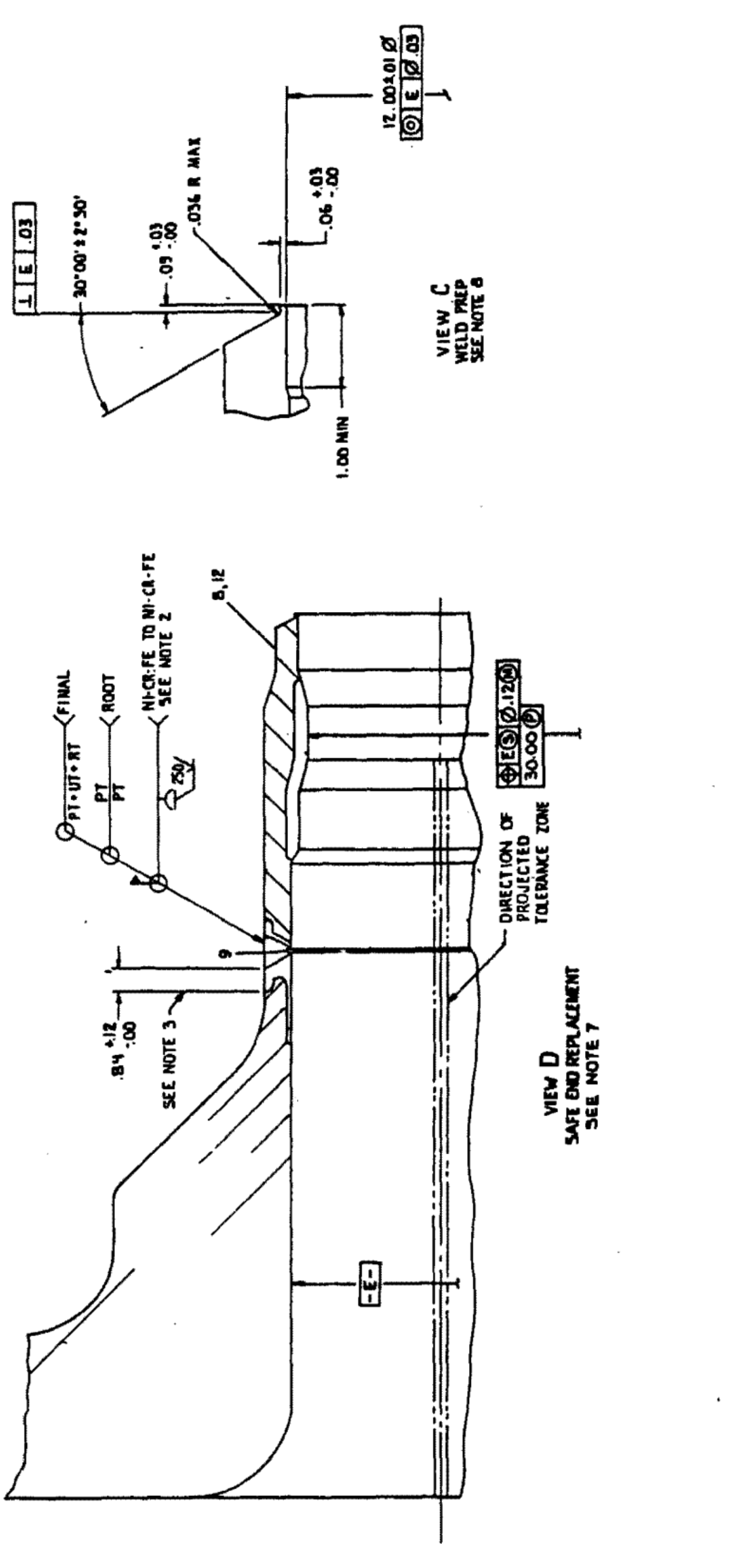
NOTES:

1. NO GRINDOUTS ARE TO BE ALLOWED ON EITHER SURFACE L OR M, EXCEPT WITHIN THE SPECIFIED DIMENSIONAL TOLERANCES. BLENDED GRINDOUTS UP TO 0.100 INCH IN DEPTH ARE PERMITTED ON OTHER SURFACES PROVIDED THEY DO NOT ENCROACH ON SURFACES L OR M.
2. PT ALL SURFACES TO BE OVERLAYED AND ALL FINAL BASE MATERIAL MACHINED SURFACES PER ASME SECTION 5, ARTICLE 6, AND MEET THE ACCEPTANCE CRITERIA OF ASME SECTION III, PARAGRAPH NB-2540.
3. MATERIAL PROCESSING CONTROL PER P50YP107.
4. ALL DIAMETERS, UNLESS OTHERWISE INDICATED, TO BE ↗ C .015 TOTAL
5. PACKAGING & SHIPPING PER 21A8774.
6. CARBON STEEL SAFE END SHALL NOT BE POST WELD HEAT TREATED.
7. NPT STAMP AND ALL OTHER DATA REQUIRED BY NA-8200 AND PART NO. GE 112D1716P_ (APPLICABLE PT NO.) SHALL BE APPLIED ON THE SURFACE INDICATED.
8. APPLY CLAD OVERLAY PER P50YP140 EXCEPT THAT PARAGRAPH 3.2.1.3 IS REVISED AS FOLLOWS: "THE MINIMUM FERRITE CONTENT OF THE FILLER MATERIAL SHALL BE 8.0 FN (FERRITE NUMBER). WHEN DEPOSITED, THE FERRITE CONTENT AT A CLADDING THICKNESS OF 0.25 INCHES AND THE FINAL SHOP CLAD SURFACE SHALL BE A MINIMUM OF 8.0 FN. IF THE FERRITE CONTENT ON THE 0.25 INCH THICK SURFACE IS BELOW 8.0 FN, THE FERRITE CONTENT OF THE NEXT DEPOSITED WELD LAYER SHALL BE A MINIMUM OF 8.0 FN. A MINIMUM OF SIX FERRITE READINGS SHALL BE TAKEN EQUALLY SPACED ON THE SURFACE AND SHALL BE AVERAGED TO A SINGLE FERRITE NUMBER. THE FERRITE NUMBERS SHALL BE DETERMINED BY A FERRITESCOPE OR MAGNE GAGE WHICH HAS BEEN CALIBRATED IN ACCORDANCE WITH AWS A4.2-74.
9. RT PER P50YP140 EXCEPT THAT PARAGRAPH 4.1 IS REPLACED WITH THE FOLLOWING: "THE COMPLETED STAINLESS STEEL CLADDING SHALL BE RADIOGRAPHICALLY EXAMINED PER ASME CODE SECTION III, ARTICLE NB-5000. PENETRAMETER AND ACCEPTANCE CRITERIA SHALL BE SELECTED BASED ON FINISHED PART THICKNESS. RADIOGRAPHIC FILM SENSITIVITY SHALL BE 2-2T, USING M GRADE FILM OR BETTER AND A SOURCE SIDE PENETRAMETER."
10. PREHEAT FOR STAINLESS STEEL OVERLAY SHALL BE A MINIMUM OF 200°F WHICH SUPERSEDES PARAGRAPH 3.3.6 OF P50YP140.
11. NICKEL-CHROME-IRON WELD BUTTERING SHALL BE PERFORMED IN ACCORDANCE WITH P50YP156 EXCEPT THAT PARAGRAPH 3.3.6, THE LAST SENTENCE OF PARAGRAPH 3.1.3 AND THE WORDS ".....AFTER PWHT" IN PARAGRAPH 3.4.1 ARE TO BE DELETED.
12. RT NI-CR-FE WELD BUTTERING PER P50YP156. ACCEPTANCE STANDARD BASED ON THE FINAL MACHINED THICKNESS OF WELD.

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SAFE END FEEDWATER NOZZLE

FIGURE 5.3-22

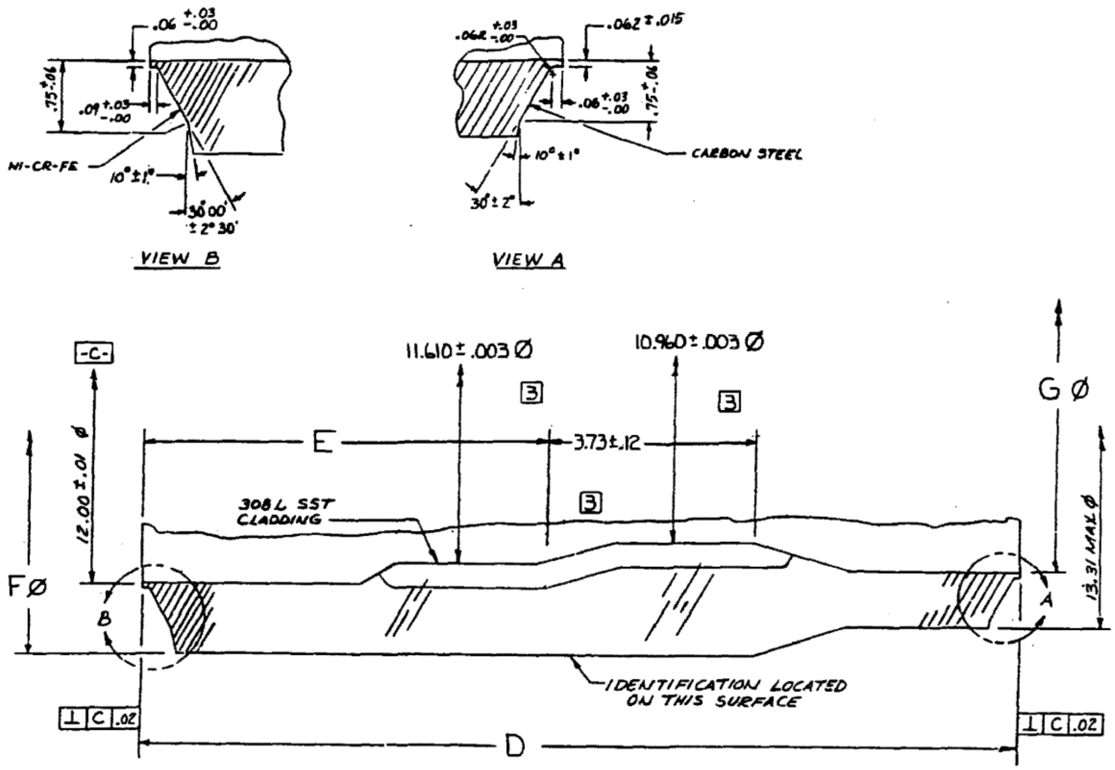


GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS
REPORT

SAFE END WELD PREP DETAILS

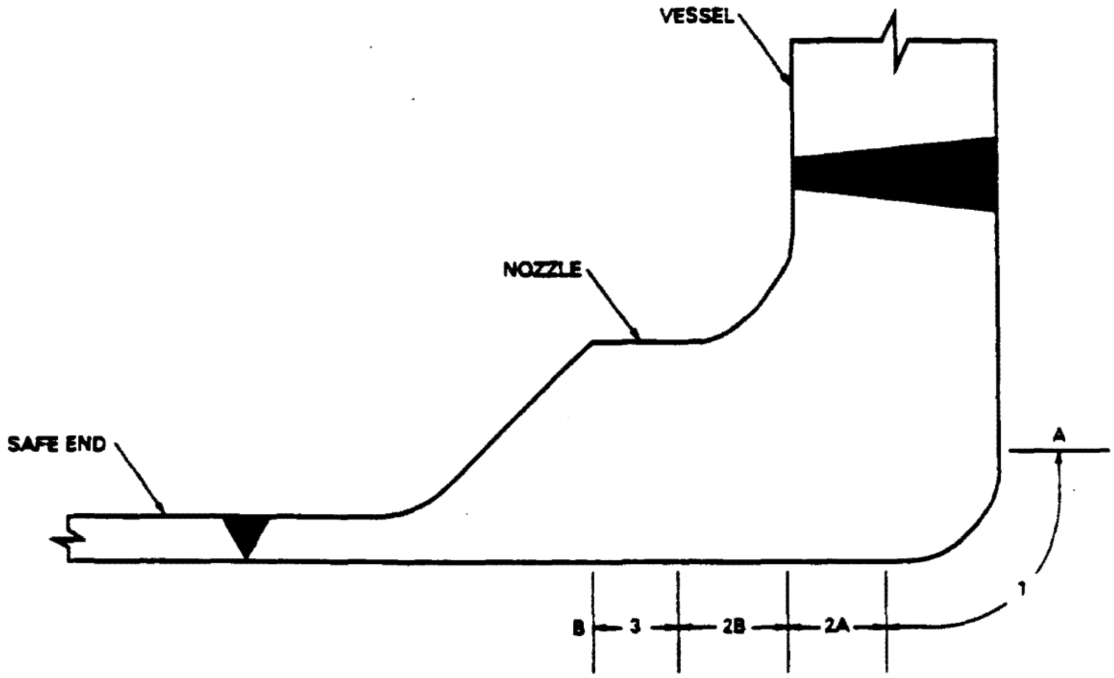
FIGURE 5.3-23

FIGURE 5.3-24 DELETED



PART NO.	D MAX	E ± .03	F MAX	APPROX WEIGHT (LB)	G ± .010
1	13.66	6.50	14.31	196	11.507
2	13.66	6.50	14.19	189	11.507
3	13.16	6.00	14.31	190	11.507
4	13.16	6.00	14.31	198	11.234

GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	OUTLINE SAFE END FEEDWATER NOZZLE FIGURE 5.3-25



The examination region begins at the inner radius-to-vessel intersection point (A). The examination region ends at the point on the inner diameter corresponding to the point on the outer diameter where the taper on the nozzle thickness starts (B).

GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	FEEDWATER NOZZLE EXAMINATION ZONES FIGURE 5.3-26

5.4 COMPONENT AND SUBSYSTEM DESIGN

5.4.1 Reactor Recirculation System

5.4.1.1 Safety Design Bases

The reactor recirculation system has been designed to meet the following safety design bases:

a. An adequate fuel barrier thermal margin shall be assured during postulated transients.

b. A failure of piping integrity shall not compromise the ability of the reactor vessel internals to provide a refloodable volume.

c. The system shall maintain pressure integrity during adverse combinations of loadings and forces occurring during abnormal, accident, and special event conditions.

5.4.1.2 Power Generation Design Bases

The reactor recirculation system meets the following power generation design bases:

a. The system shall provide sufficient flow to remove heat from the fuel.

b. System design shall minimize maintenance situations that would require core disassembly and fuel removal.

5.4.1.3 Description

The reactor recirculation system consists of the two recirculation pump loops external to the reactor vessel. These loops provide the piping path for the driving flow of water to the reactor vessel jet pumps. (See Figure 5.4-1.) Each external loop contains one high capacity motor-driven recirculation pump, a flow control valve, and two motor-operated gate valves (for pump maintenance). Each pump suction line contains a flow measuring system. The recirculation loops are part of the reactor coolant pressure boundary and are located inside the drywell structure. The jet pumps are reactor vessel internals. Their location and mechanical design are discussed in subsection 3.9.5, Reactor Pressure Vessel Internals. However, certain operational characteristics of the jet pumps are discussed herein.

A tabulation of the important design and performance characteristics of the reactor recirculation system is shown in Table 5.4-1. The head, NPSH, flow, and efficiency curves are shown in Figure 5.4.4. Instrumentation and control description is provided in Chapter 7.

The recirculated coolant consists of saturated water from the steam separators and dryers that has been subcooled by incoming feedwater. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the driven flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The flows, both driving and driven, are mixed in the jet pump throat section and result in partial pressure recovery. The balance of recovery is obtained in the jet pump diffusing section (see Figure 5.4-6). The adequacy of the total flow to the core is discussed in Section 4.4, Thermal and Hydraulic Design.

The allowable heatup rate for the recirculation pump casing is the same as the reactor vessel. If one loop is shut down, the idle loop can be kept hot by leaving the valves as follows: pump suction and discharge valves open and flow control valve in minimum position, permitting the pressure head created by the active jet pumps to cause reverse flow in the idle loop.

When the pump is operating at 25 percent speed, the head provided by the elevation of the reactor water level above the recirculation pump is sufficient to provide the required NPSH for the recirculation pumps, flow control valve and jet pumps. When the pump is operating at 100 percent speed, most of the NPSH is supplied by the subcooling provided by the feedwater flow. Accurate temperature detectors are provided in the recirculation lines and the steam dome where steam pressure is converted to saturated temperature. The difference between these two readings is a direct measurement of the subcooling. If the subcooling falls below approximately 8 F, the 100 percent power supply is tripped to the 25 percent power source to prevent cavitation of the recirculation pump and jet pumps.

When preparing for hydrostatic tests, the nuclear system temperature must be raised above the vessel nil ductility transition temperature limit. For such tests, heatup is usually accomplished using RHR and/or decay heat. Except during the preoperational hydrostatic test, the recirculation pumps can be used for such heatup when there is enough NPSH to allow 100 percent speed operation. Jumper connections to defeat the interlocks shall be provided to allow such operation when circumstance demands. However, these connections shall only be used when NPSH is adequate and appropriate operating procedures are strictly enforced. Thus, if necessary, the recirculation pumps can be made available to the supply heat to raise the system temperature.

The recirculation pump is driven by an induction motor and is equipped with mechanical shaft seal assemblies. The two seals built into a cartridge can be readily replaced without removing the motor from the pump. Each individual seal in the cartridge is designed for pump operating pressure so that any one seal can adequately limit leakage in the event that the other seal should fail. The pump shaft passes through a breakdown bushing in the pump casing to reduce leakage in the event of a gross failure of both shaft seals. The cavity temperature and pressure drop across each individual seal can be monitored.

Each recirculation pump motor is a vertical, solid shaft, totally enclosed, air-water cooled, induction motor. Its performance under normal and low speed is given in Table 5.4-1. The combined rotating inertias of the recirculation pump and motor provide a slow coastdown of flow following loss of power to the drive motors. This inertia requirement is met without a flywheel.

The pump discharge flow control valve can throttle and discharge flow of the pump proportionally to an instrument signal. The flow control valve has an equal percentage characteristic. The recirculation loop flow rate can be rapidly changed, within the expected flow range, in response to rapid changes in system demand.

The design objective for the recirculation system equipment is to provide units that will not require removal from the system for rework or overhaul. Pump casing and valve bodies are designed for a 40-year life and are welded to the pipe.

The pump drive motor, impeller, and wear rings and flow control valve internals are designed for as long a life as is practical. Pump mechanical seal parts and the valve packing are expected to have a life expectancy which affords convenient replacement during the refueling outages.

The recirculation system piping is of all-welded construction and is designed and constructed to meet the requirements of the applicable ASME and ANSI Codes.

The reactor recirculation system pressure boundary equipment is designed as seismic Category I equipment. As such, it is designed to resist sufficiently the response motion at the installed location within the supporting structure for the safe shutdown earthquake. The pump is assumed to be filled with water for the analysis. Vibration snubbers located at the top of the motor and at the bottom of the pump casing are designed to resist the horizontal reactions.

The recirculation piping, valves, and pumps are supported by hangers to avoid the use of piping expansion loops that would be required if the pumps were anchored. In addition, the recirculation loops are provided with a system of restraints designed so that reaction forces associated with any split or circumferential break do not jeopardize drywell integrity. This restraint system provides adequate clearance for normal thermal expansion movement of the loop. The criteria for the protection against the dynamic effects associated with a loss-of-coolant accident are contained in Section 3.6.

The recirculation system piping, valves, and pump casings are covered with thermal insulation having a total maximum heat transfer rate of 65 Btu/hr-ft^2 with the system at rated operating conditions. This heat loss includes losses through joints, laps, and other openings that may occur in normal application.

The insulation is the all-metal reflective type. It is prefabricated into components for field installation. Removable insulation is provided at various locations to permit periodic inspection of the equipment.

A layout of the external piping and the major equipment is shown on Figure 5.4-30. Their orientation with respect to the reactor pressure vessel is given.

5.4.1.4 Safety Evaluation

5.4.1.4.1 General

Reactor recirculation system malfunctions that pose threats of damage to the fuel barrier are described and evaluated in Chapter 15, Accident Analyses. It is shown in Chapter 15 that none of the malfunctions results in significant fuel damage. The recirculation system has sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational transients.

[HISTORICAL INFORMATION] [The core flooding capability of a jet pump design plant is discussed in detail in the emergency core cooling systems document filed with the NRC as a General Electric topical report (Ref. 1). The ability to reflood the BWR core to the top of the jet pumps as shown schematically in Figure 5.4-7, and as discussed in Reference 1 applies to all jet pump BWRs and does not depend on the plant size or product line.

Piping and pump design pressures for the reactor recirculation system are based on peak steam pressure in the reactor dome, appropriate pump head allowances, and the elevation head above the lowest point in the recirculation loop. Piping and related equipment pressure parts are chosen in accordance with applicable codes. Use of the listed code design criteria assures that a system designed, built, and operated within design limits has an extremely low probability of failure caused by any known failure mechanism.

General Electric purchase specifications require that the recirculation pumps first critical speed shall not be less than 130 percent of operating speed. Calculation submittal is required and verified by General Electric design engineering.

General Electric purchase specifications require that integrity of the pump case be maintained through all transients and that the pump remain operable through all normal and upset transients. The design of the pump and motor bearings is required to be such that dynamic load capability at rated operating conditions is not exceeded during the safe shutdown earthquake. Calculation submittal to General Electric is required.

Pump overspeed occurs during the course of a LOCA due to blowdown through the broken loop pump. Design studies determined that the overspeed was not sufficient to cause destruction of the motor; consequently no pump decoupler is provided.]

5.4.1.4.2 Compliance with General Design Criteria

The recirculation flow control system is evaluated against the General Design Criteria as follows:

a. Criteria 20, 21, 23 and 25: Applicable to protection systems only. The recirculation flow control system is a reactivity control system but is not a protection system.

b. Criterion 26: The recirculation flow control system is the second reactivity control system required by this criterion. The requirements of this criterion do not apply within the system itself.

c. Criterion 27: The recirculation flow control system is not intended to control reactivity following an accident. Consequently, this criterion does not apply.

d. Criterion 28: The transient analyses in Chapter 15 evaluate the consequences of reactivity events involving changes in reactor coolant temperature and pressure, and cold water addition. The results of these analyses indicate that none of these postulated events result in damage to the reactor coolant pressure boundary. In addition, the integrity of the core, its support structures and other reactor pressure vessel internals are maintained so that the capability to cool the core is not impaired for any of these events.

5.4.1.5 Inspection and Testing

[HISTORICAL INFORMATION] [Quality control methods were used during fabrication and assembly of the reactor recirculation system to assure that design specifications are met. Inspection and testing is carried out as described in Chapter 3. The reactor coolant system is thoroughly cleaned and flushed before fuel is loaded initially.

During the preoperational test program, the reactor recirculation system is hydrostatically tested at 125 percent reactor vessel design pressure. Preoperational tests on the reactor recirculation system also included checking operation of the pumps, flow control system, and gate valves.

During the startup test program, horizontal and vertical motions of the reactor recirculation system piping and equipment are observed; supports are adjusted, as necessary, to assure that components are free to move as designed. Nuclear system responses to recirculation pump trips at rated temperatures and pressure are evaluated during the startup tests, and plant power response to recirculation flow control is determined.]

5.4.1.6 Operation

Salient recirculation system operations are discussed in this section. More detailed description may be found in the appropriate operator manuals. The operation in terms of the power flow operating map is discussed in Chapter 4.

5.4.1.6.1 Normal Operation

Normal plant operation presumes that no abnormal condition exists due to such events as scram, operator error, or turbine trip. In this context, an operator error is considered an action that is contrary to plant operating procedures.

5.4.1.6.1.1 Start

The system is started after the core is loaded, the vessel internals installed, the head is in place and the water level is at least at the normal level. The system valves are oriented to their startup positions as follows:

a. Initial conditions (recirculation system):

   1. Discharge valve open

   2. Suction valve open (allows cleanup suction from the recirculation loops);

   3. Flow control valve in minimum position; and

   4. Pump off

b. Startup procedures

1. Start pump (the automatic sequencing enables the 100 percent speed power supply to start the pumps, closes the low frequency motor generator (LFMG) motor feeder breaker to bring it up to speed, trips the 100 percent speed supply when 90 to 100 percent speed is reached and closes the LFMG output breaker when the pump has coasted down to approximately 25 percent speed); and

2. Open FCV to the maximum position.

5.4.1.6.1.2 Heatup and Pressurization

During vessel pressurization and heatup to rated conditions, the system is run by the LFMG set at 25 percent speed with the FCV at the maximum position.

5.4.1.6.1.3 Low Thermal Power

Power ascension up to 30 percent to 40 percent power is accomplished by pulling control rods. The recirculation system operating mode is 25 percent speed with the flow control valve at the maximum position.

5.4.1.6.1.4 High Thermal Power

The system is transferred to 100 percent speed after the flow control valve cavitation interlock is cleared.

This allows further power ascension by core flow control as well as by control rod movement.

a. transfer procedure (power ascension):

   1. Close the FCV to the minimum position.

   2. Transfer to 100 percent speed - FCV minimum position (the automatic sequencing opens the LFMG generator breaker, opens the LFMG motor feeder breaker and closes the 100 percent speed breaker).

b. transfer sequence (normal shutdown):

   1. Close FCV's to minimum position (100 percent speed).

2. Transfer to 25 percent speed - FCV minimum position (the automatic sequencing opens the 100 percent speed breaker, closes the LFMG motor feeder breaker and closes the LFMG generator breaker when the pump has coasted down to 25 percent speed).

3. Open FCV's to maximum position.

5.4.1.6.1.5 Power - Flow Control

Refer to subsection 4.4.3.3 for a description of power-flow control. A power-flow operating map, Figure 4.4-5 shows normal operational limits, and shows regions of operation.

5.4.1.6.2 Abnormal Operation

Abnormal operation is defined as any operation other than normal routine and includes such events as operator error, plant operational transients such as MSIV closure and turbine trip, or an accident condition, such as a recirculation suction line double-ended pipe break.

The recirculation system is designed to achieve the following two major objectives for abnormal operation:

a. Plant Safety - those system functions required to mitigate an abnormal operational event, that is, functions for which credit is taken in the event analysis; and

b. Power Generation - those functions necessary to maximize power generation capability and ensure longevity of equipment. These functions prevent steady-state operation of system equipment in modes where damage can occur and prevent unnecessary reactor protection system (RPS) activation. Equipment damage would make it necessary to inspect or replace equipment during an outage thereby increasing plant unavailability. Unnecessary scrams also increase plant unavailability.

5.4.1.6.2.1 Safety

5.4.1.6.2.1.1 Moderate and Infrequent Events

Trip of the recirculation pumps is needed to mitigate the effects of turbine or generator trip events.

5.4.1.6.2.1.2 Accident Events

Trip of the recirculation pumps is needed to mitigate the vessel overpressure transient and reduce core power level for the anticipated transient without scram (ATWS) event.

5.4.1.6.2.2 Power Generation

5.4.1.6.2.2.1 Cavitation Interlocks

There are three cavitation interlocks:

- ΔT – temperature difference between the recirculation pump temperature and the saturation temperature at the steam dome pressure.
- Total Feedwater Flow Interlock- will initiate an automatic transfer to slow speed if total feedwater flow falls below 22%.
- Low Water Level Interlock- downshifting of pumps occurs if vessel water level decreases to level 3 (+11.4") which is also the Level 3 Scram.

Two cavitation interlocks, total feedwater flow and low water level interlock, are installed to provide protection against:

a. Operator errors, and

b. Rapid transients such as SCRAM where NPSH conditions deteriorate rapidly and the operator is not expected to respond in time to prevent long-term operation in the cavitation. If feedwater flow decreases to less than 22%, then the recirculation pumps down shift and if level decreases to less than level 3, then the recirculation pumps down shift. If feedwater were to continue to feed in a rapid transient, then Level 9 (+58") would trip the feedwater turbines and cause the total feedwater flow to decrease to less than 22% and downshift the recirculation pumps.

5.4.1.6.2.2.2 Feedwater Pump Trip Runback

The flow control valves close in response to a trip of one feedwater pump and indication of a reactor water level decrease (level drops to Level 4) provided recirculation pump speed is greater than 95 percent. This runback prevents a scram from a low level condition caused by the feedwater pump trip.

5.4.1.6.2.2.3 Flow Control Valve Minimum Position Interlock

The interlock is installed to prevent system startup or transfer from 25 percent to 100 percent speed unless the valve is in the minimum position. The objective is to prevent scrams due to a rapid flow increase resulting from an operator failure to close the FCV prior to the start of speed transfer.

5.4.1.6.2.2.4 LFMG Output Breaker Control

The LFMG set output breaker closing logic includes interlocks which prevent breaker closure until the 100 percent power supply is tripped and residual voltages in the motor have decayed. These interlocks prevent possible damage to the generator which could result if the generator was connected to the pump while the 100 percent speed power supply was still active.

5.4.1.6.2.2.5 High Loop Flow Mismatch

Mismatch of the flow in one loop to the other loop of greater than 50 percent is known to create abnormal conditions in the jet pumps having the lower flow. Such operation is normally precluded by operating procedures.

5.4.1.6.2.2.6 Loop Suction and Discharge Isolation Valve Position

The pump is tripped for isolation valve positions less than 90 percent open to prevent pump damage from no flow if isolation valve closure is inadvertently initiated while the pumps are running.

5.4.1.6.2.2.7 Trip to 25 Percent Speed

The LFMG set is activated in most 100 percent speed trip cases to avoid scram recovery delays due to vessel bottom head fluid stratification.

5.4.1.6.3 One Pump Operation

5.4.1.6.3.1 One Recirculation Pump Operation

[HISTORICAL INFORMATION] [The automatic interlocks do not fully protect against jet pump cavitation in this operating mode. Reactor operation is limited to the areas above the jet pump nozzle cavitation line "N" in Figure 5.4-31. The flow control valve cavitation interlock remains functional in this operating mode.]

Single loop operation at reduced power is allowed at GGNS in accordance with the Technical Requirements Manual LCO TR3.4.1 and plant operating procedures. Appendix 15C addresses analyses performed by GEH for the initial fuel cycle. Discussions applicable to the current fuel cycle are provided in the appropriate sections in the main body of the UFSAR. Single loop operation is restricted to off-rated conditions of 2705 MWt and core flow of 60.9 Mlb/hr. These restrictions have not changed since initial power operations as described in the PUSAR Section 2.8.4.6.3.

5.4.1.6.3.2 Restart of One Recirculation Pump

In order to maintain plant availability, it is necessary to follow specific procedures for restart of one pump to return to two-pump operation. Otherwise, a scram will result. Specific procedures to avoid scram are determined during startup testing and include reducing active pump flow to at least 50 percent before starting the inactive pump.

5.4.1.6.4 Power Level Manipulations

5.4.1.6.4.1 Deleted

5.4.1.6.4.2 Deleted

5.4.1.6.4.3 Load Maneuvering Capability

BWR power output can be adjusted to meet the system requirements by manual adjustment of control rods or manual adjustment of reactor recirculation flow. Referring to Figure 4.4-5 power rod lines sloping up to the right show how power changes when control rods are held constant while core flow is changed. Nearly vertical lines leaning slightly to the left show how power changes when control rods are moved and recirculation drive flow is held constant. During normal operation, the plant would operate within region IV and probably on the rated power rod line. Power rod lines are identified by their power at rated (100 percent) core flow (e.g., the line passing through 80 percent power at 100 percent flow is called the 80 percent rod line).

The purpose of changing recirculation flow is to change core flow and thereby alter the core void sweep characteristic which changes neutron flux and, hence, power output. The advantages of regulating the power output with recirculation flow rather than with control rods are that power changes using core flow are more specially uniform and are faster.

The recirculation control system consists of two parallel loops with individual flow control valves, valve actuators, and flow controllers. The desired recirculation flow is achieved by manually positioning each of the Flow Control Valves with the raise/lower lever provided on each flow controller. Automatic flow control and the neutron flux loop have been disabled.

5.4.1.6.4.4 Deleted

5.4.1.6.4.5 Turbine-Generator Speed-Load Controls

The speed-load controls module generates an output signal called unbiased load demand, which is the sum of the load set point and the amplified speed error. On domestic plants the speed regulation is 5 percent (i.e., 5 percent turbine speed error input yields 100 percent demand change output). The load set point is the signal that is changed by the operator. The output signal going to the low-value gate is biased positive by a small amount (~10 percent), so that the normal control signal to the turbine control valves is the pressure regulator output signal.

5.4.1.6.4.6 Pressure Set Point Adjuster

The function of the pressure set point adjuster is simply to maximize the area under the steam flow response curve on increasing signals (minimize on decreasing signals) by temporarily decreasing (increasing) the pressure set point to allow utilization of some of the energy stored in the vessel (store more energy in the vessel).

5.4.1.6.4.7 Deleted

5.4.1.6.4.8 Deleted

5.4.1.6.4.9 Deleted

5.4.1.6.5 Trip and Start Functions

The power supplies to the pump motor are tripped or started as shown in Table 5.4-2. This table describes a number of possible recirculation events and then shows in tabular form the actions which result.

5.4.1.6.6 Suction and Discharge Block Valve Operation

The 24-inch suction and discharge motor-operated gate valves provide pump and flow control valve isolation during maintenance. The operators take 2 minutes to either fully open or close the valve. Both the suction and discharge valves are capable of closing against the calculated maximum expected differential pressure. The maximum expected differential pressure has been determined by a design basis review and differential pressure calculation performed in response to NRC Generic Letter 89-10 and found to be 34 psid. Both valves are remote-manually operated.

5.4.1.6.7 Residual Heat Removal System Operation

One of the sources of water supply for the RHR System operation is the suction side of Loop B of the Recirculation System. The RHR system uses this suction source during the shutdown cooling mode.

5.4.1.7 Safety-Related Considerations

5.4.1.7.1 Pressure Integrity

Design pressures for the reactor recirculation system are based on peak steam pressure in the reactor dome, appropriate pump head allowances, and the elevation head above the lowest elevation in the recirculation loop. Piping and related equipment pressure parts are chosen in accordance with applicable codes. Use of the code design criteria assures that a system designed, built, and operated within design limits has an extremely low probability of failure caused by any known failure mechanism.

5.4.1.7.2 Bearing Load Capability

In order to assure functional performance of the recirculation pump and motor, the following additional requirement is met:

The pump and motor bearings shall have sufficient dynamic load capability at rated operating conditions to withstand the safe shutdown earthquake and to be able to coast down to 40 percent of rated speed on loss of power.

5.4.1.7.3 Pump Shaft Critical Speed

The first critical speed of the recirculation pump shaft has been calculated to be about 130 percent of the operating speed. The absence of shaft vibration has been verified by testing the pump under rated speed conditions in the supplier's test loop. The absence of vibration is further verified during preoperational testing.

5.4.1.7.4 Pump Bearing Integrity

Adequacy of the bearing design has been verified by full temperature and pressure tests in the supplier's test loop.

5.4.1.7.5 Pipe Rupture

Protection against dynamic effects of pipe rupture is described in Section 3.6 of the FSAR. Protection has been provided for the postulated break locations and break types.

5.4.1.7.6 Suction and Discharge Block Valve Close Rate

Valves will not close in such a manner that would affect the coastdown flow rate of the pump. An analysis was made to determine the effect of block valve closure on recirculation pump coastdown. The analysis postulates that coincident with a recirculation pump trip, the block valves begin to close. It was concluded that any closure time greater than 1 minute will have no effect on coastdown times.

5.4.1.7.7 Flow Control Valve Actuator Stroking Rate

The worst single failure or operator error would result in a valve actuator stroking rate within the limitations stated in subsection 5.4.1.9.1.

5.4.1.7.8 Loop Flow Balance

The design-basis loss-of-coolant accident analyses assume that the total flow through one bank of jet pumps is close to the total flow of the other bank. If it is assumed that one bank is at a higher flow than the other and a design-basis pipe rupture occurs in the high-flow loop, calculated peak cladding temperatures higher than those calculated in the DBA analysis could result, since the low flow loop could not provide as much flow during the first few seconds of the transient. Consequently, loop flow imbalance restrictions are placed on the system.

5.4.1.7.9 Thermal Shock

When the recirculation system is inactive and thermal power is too low to support much natural circulation flow, stratification of water in the recirculation loops or vessel bottom head can occur. If core flow is increased in such a condition, rapid replacement of cold with hot water shocks the adjacent components increasing their usage. Although the reactivity transient on the core is not significant, the increased usage is not acceptable. Consequently, restrictions are placed on allowable inactive loop suction temperature before startup and on core flow increases based on bottom head drain line to vessel saturation temperature.

5.4.1.7.10 Anticipated Transients Without Scram (ATWS)

Trip of the recirculation pumps is needed to inhibit steam production if an anticipated transient without scram occurs. Steam production would be inhibited by the retention of voids (steam bubbles) which would reduce thermal output due to the resultant negative reactivity. The reduced thermal output would reduce unwanted steam that would otherwise discharge to the suppression pool.

For the purpose of mitigating the consequences of an ATWS, the recirculation pump motors (normal and low frequency power supplies) trip off (recirculation pump trip system) on an ATWS signal provided by the system (either on two-out-of-two high reactor dome pressure or on two-out-of-two low-low water level in the reactor vessel). The ATWS-recirculation pump trip system at GGNS utilizes redundant breakers for each power feed (low and high speed to each pump). A single breaker with one energize-to-trip coil in each power feed will be tripped by an independent trip system. There are two independent trip systems.

The recirculation pump has rotational inertia as specified in Table 5.4-1. When tripped, the recirculation pump continues pumping the water in the recirculation loop during the coastdown period but at a decreasing rate.

5.4.1.8 Flow Control Components Description

5.4.1.8.1 Flow Control Valves (FCV)

The FCV is a ball valve with a linkage connected to the actuator shaft.

The Flow Control Valve (FCV) with the enclosed topworks consists of the body, the bonnet, shaft/ball assembly, the upper cover, the packing cartridge, the yoke and the actuator with the hydraulic lines.

The forces required to actuate the valve vary with the position:

a. To open the valve, the extend force varies from approximately 27,000 lb to approximately 4,000 lb.

b. To close the valve, the force varies from approximately 15,000 to approximately 2,000 lb.

Should the valve ball seize, the hydraulic actuator is capable of producing a maximum force of 56,300 lb. The most severely stressed part would be the link. At the maximum actuator force the stress would be about equal to the yield stress.

All other parts are stressed below their yield points, and no failure is therefore expected.

The result of the above failures would not affect the pressure integrity of the valve or allow the ball to break away from the shaft.

The following are definitions of the positions of the flow control valve:

Closed position - the fully closed position of the valve ball. This is a reference position for identifying valve ball angular position. Physically, the valve cannot reach this position.

Minimum or Zero Position - the most closed actual valve position. This is the ball position that establishes approximately 25 percent rated pump flow at 100 percent speed. This ball position is approximately 26° from the closed position.

Maximum Position - 1.) When the recirculating pump is in slow speed valve travel is limited by the maximum actuator stop. This is also defined as the 100% valve position. 2.) When the recirculating pump is in fast speed and the Flow Controller is in automatic, valve travel is limited by the Flow Controller. The Flow Controller limit is adjusted to prevent exceeding any operating thermal limit.

Stroke - Valve travel between the zero and maximum actuator stop.

5.4.1.8.2 Flow Control Valve Actuator

The actuator consists of a custom, double acting, dual rod, hydraulic cylinder; pilot operated check valves (for lock up); a velocity limit orifice (to limit stroking rate); circulation orifices (to prevent stagnation and aeration); and a linear velocity transducer and limit switches (to provide necessary signals to electrical control systems). Hydraulic components are manifolded together to enhance reliability. The cylinder is designed specifically to meet the performance, environmental, duty cycle, and dimensional and load interface requirements of this application. Dual seals, separated by a drain cavity, are provided for each rod.

All portions of the actuator, other than the drain circuits, are rated for operation at 3000 psi. The drain circuit is rated for operation at 150 psi. Each actuator is hydrostatically tested by the manufacturer at 4500 psi except for the drain circuits which are tested at 2000 psi. The normal operating pressure is 1850 psi to 1950 psi, and the drain pressure is less than 150 psi.

5.4.1.8.3 Circulation Unit

The circulation unit, located outside the drywell, consists of a manifold and two circulation orifices which, in conjunction with the circulation orifice on the actuator, provide a small circulation flow through the interconnecting piping to prevent stagnation and aeration. The circulation unit is rated for operation at 3000 psi and hydrostatic testing at 4500 psi.

Circulation flow is returned to the reservoir by a drain line from the circulation unit.

5.4.1.8.4 Hydraulic Power Unit

The hydraulic power unit, located outside the drywell, is a skid mounted unit incorporating the reservoir, pumping units, pressure and flow control valves, fluid conditioners, and alarm and indicating devices. Extensive use of manifolds, a rigid base structure, very fine filtration, and a high degree of redundancy enhance reliability. All circuits which are subjected to the normal operation pressure of 1850 to 1950 psi are rated for operation at 3000 psi or greater and are designed to withstand a hydrostatic test pressure of 4500 psi.

5.4.1.8.5 Interconnecting Piping and Drain and Vent Valves

The piping which interconnects the actuator, circulation unit, and hydraulic power unit is sized to meet both strength and performance requirements. All pipe is seamless stainless steel. Design pressure is 2000 psi for all piping to the actuator and 100 psi for the circulation unit drain line. Any commercial components not designed and manufactured in accordance with ANSI B31.1 are rated for operation at 1.5 times design pressure.

5.4.1.8.6 Hydraulic Fluid

The hydraulic fluid used is Fyrquell EHC. This is a phosphate ester fluid which has the lubricity, viscosity and other characteristics necessary for performance and reliability while providing protection against fire.

5.4.1.8.7 Hydraulic Equipment

Each flow control valve has a separate set of hydraulic equipment. The hydraulic circuit for each FCV is composed of the actuator unit (mounted on the FCV), the circulation unit (located in the piping high point, outside the drywell), and the interconnecting piping. Drain and vent valves are located in the interconnecting piping to facilitate maintenance.

The actuator unit provides the mechanical input to the FCV. The circulation unit, in conjunction with the circulation valves on the actuator unit, provides a small steady flow through critical portions of the interconnecting piping to reduce stagnation and aeration and minimize the effects of ambient temperature on performance. The hydraulic power unit, in response to control signals from the electronic equipment, provides the hydraulic inputs (pressure and flow) to the actuator unit.

5.4.1.9 Flow Control System Description

5.4.1.9.1 Safety Requirements

The worst single failure or operator error shall result in an actuator stroking rate of less than or equal to 30 percent full stroke per second.

The control system shall not close the flow control valve in the unbroken loop at a rate that will affect the LOCA recirculation pump coastdown.

5.4.1.9.2 Design Description

The FCV position is varied by a hydraulic actuator mounted on the valve. Hydraulic lines lead from the actuator to a hydraulic power unit. The power unit controls the line pressure and the fluid flow to or from either side of the actuator piston, thereby changing flow control valve position.

The remainder of the system incorporates both manual and automatic features using feedback loops of actuator velocity, FCV position, recirculation loop flow, neutron flux and turbine demand.

During normal operation, actuator stroking rate is limited to 11 percent per second or less by limiting the velocity demand signal (position controller output) to an analogous value. In addition, several interlocks are provided to limit travel if the velocity is excessive. This is to ensure that the reactor protection system will not initiate a scram.

5.4.1.9.3 Valve Actuation Equipment

An electrohydraulic servo system, consisting of a velocity loop (actuator velocity) nested within a position loop (FCV ball position), moves the flow control valve in response to the position demand signal. One servo system is provided for each FCV.

A linear velocity transducer, mounted on the actuator in conjunction with suitable signal conditioners, provides an actuator velocity feedback signal. The velocity controller, a proportional plus integral plus derivative controller, compares the velocity feedback signal with the velocity demand signal and amplifies the resulting error signal. Voltage to current converters convert this output signal to one compatible with the hydraulic power unit.

The hydraulic power unit, in response to this signal directs flow to the actuator to change its velocity, and thus the velocity feedback signal, in a manner which will reduce the velocity error to zero.

Similarly, a rotary variable differential transformer, mounted on the FCV, in conjunction with suitable signal conditioners, provides an FCV position feedback signal.

The position controller, a proportional plus derivative controller, compares the position feedback signal with the position demand signal, and amplifies the resulting error signal to provide a velocity demand signal which will cause the actuator to travel in the direction necessary to reduce the position error to zero.

Limiting circuits within the position controller limit its output signal (velocity demand signal) so that sustained actuator velocity will not exceed 11 percent full stroke per second, even if large or rapid changes in the position demand signal occur.

The electronic equipment incorporates interlock circuits which will inhibit motion in the event that any of the following occur:

a. Position demand signal exceeds preset limits.

b. Actuator velocity exceeds preset limits.

c. FCV position rate of change exceeds preset limits.

d. Excessive oscillations occur.

e. Prolonged velocity error occurs (in which event an interlock may transfer operation to redundant circuits).

In addition, the various circuits are arranged such that the FCV will be locked (motion inhibited) in its last position if any of the following occur:

a. Loss of control signal to hydraulic power unit (HPU).

b. Loss of electrical power to HPU.

c. Loss of control power.

d. Loss of hydraulic power.

5.4.1.9.4 Circuit Description

A brief circuit description of the hydraulic equipment follows to explain how the equipment functions:

A. Actuator Unit and Circulation Unit

The hydraulic cylinder provides the mechanical input to the FCV in response to flow from the HPU. When the HPU directs flow to the "open" port and allows flow from the "close" port to vent the reservoir the cylinder moves the FCV stem to open the valve. When flow is reversed, FCV motion reverses. Velocity is proportional to flow. During normal operation, the HPU directs pressure, via the "pilot" line, to the pilot ports of the pilot operated check valves on the actuator unit.

This pressure opens the valves allowing flow to and from the cylinder's "open" and "close" ports. In the event of a manual or interlock initiated shutdown, the HPU vents the pressure from the pilot operated check valves, closing them to trap fluid in the cylinder and thus inhibit motion. Since a loss of pilot pressure closes the pilot operated check valves, loss of hydraulic power inhibits motion.

The velocity limit orifice, located at the cylinder "open" port, restricts flow to and from the port, thus limiting velocity in the event that malfunctions disable the normal electronic velocity limiting circuits.

The desired circulation flow is provided by four circulation valves. The two circulation valves on the actuator direct small equal flows from the "pilot"-line to the "open" and "close" lines, while the two identical valves on the circulation unit direct these flows back to the HPU reservoir.

B. Hydraulic Power Unit

The HPU consists of two identical, redundant subloops for the generation and control of hydraulic flow and pressure. The subloops are interconnected at the lines which direct flow and pressure to the actuator unit and at the common reservoir and drain header. Normally, only one subloop is pressurized at a time. If a hydraulic malfunction occurs while the subloop is controlling the actuator, it will automatically shut down and the alternate subloop will automatically start and assume control. If a second malfunction occurs, the alternate subloop will also shut down.

Fluid storage is provided by the common reservoir. Hydraulic power is generated by the operating subloop's electric motor driven pump. The pump is the fixed displacement, positive displacement type, and thus provides constant flow irrespective of demand or pressure. Pressure is controlled by the operating subloop's relief valve which limits pressure to the required value by metering unneeded flow back to the reservoir. The operating subloop's accumulator reduces pressure transients by providing an absorbing flow when demand changes faster than the relief valve can respond.

Flow to and from the "open" and "close" ports of the actuator is controlled by the operational subloop's servo valve, in response to the electronic signal from the electronic equipment.

Reversing the polarity of the signal reverses the flow paths through the servo valve, thus reversing the direction of the actuator motion. Increasing the magnitude of the signal increases the opening of the servo valve, increases flow, and thus actuator velocity.When the signal is zero, the servo valve is closed, thus loss of signal inhibits FCV motion. It should be noted that the servo valve is of the "jet-pipe" type and is wired "parallel aiding".This type of valve and wiring will tend to fail closed (if it fails at all), inhibiting motion.

Pressure to the actuator's pilot operated check valve pilot ports is controlled by a three-position, solenoid operated, four-way valve. For maximum reliability, the valve is normally energized to power the spool to the "vent" (inhibit motion) position as well as the "pressurize" (operate) position. In the event of loss of electrical control signals, however, internal springs actuate the valve to an alternate "vent" position to close the check valves and thus inhibit motion. The solenoid valves of the alternate (non-operating) subloop is automatically isolated from the operating subloop's solenoid valve, as well as the actuator, by a shuttle valve. It should be noted that it is physically impossible for the shuttle valve to simultaneously isolate both solenoid valves from the actuator, thus shuttle valve failure cannot prevent FCV "lock-up".

The solenoid operated valves also control pilot operated four-way valves located between the servo valves and the common "open" and "close" lines. As with the solenoid valve, the pilot operated four-way valves are powered to both the "operate" (open) and "isolate" (close) positions, but will close anyway in the event of either loss of hydraulic power or loss of electrical power to the solenoid valves.When closed, this valve blocks its servo valve from the common open and close lines, as well as from the alternate subloop, and thus will inhibit motion even if the pilot operated check valves and the servo valve remain open due to malfunction.

In addition to the above components, the circuit incorporates suction, reservoir vent, pressure line, and return line filters to control fluid cleanliness for desired reliability; temperature control valves and air-oil heat exchangers to control fluid temperature for desired reliability; manually operated shut off valves and check valves to facilitate maintenance, and alarm devices and visual indicators to monitor HPU status. The alarm devices also activate interlocks within the logic circuits.

5.4.1.9.5 Hydraulic Power Unit Logic Controls

5.4.1.9.5.1 General Description

The HPU for each FCV is controlled by a separate set of electrical logic circuits. The logic circuits also provide switching functions within the analog control circuits which form the velocity loops.

The "heart" of the logic circuits is a programmable controller. Based on the various inputs to it (operator pushbuttons, HPU and analog circuit alarm devices, etc.) the programmable controller provides outputs to switch analog circuits, control HPU motors and solenoids, power indicator lights, etc. Where contact closure is necessary in lieu of an AC or DC signal (annunciators, motor controls, etc.), interface relays are provided.

Essentially, the programmable controller performs the same function often performed by a large number of "instantaneous" and delayed response relays.

5.4.1.9.5.2 Functional Description

The logic circuits allow the operator to select which redundant subloop will control the FCV actuator, and whether or not the alternate subloop will start automatically and assume control in the event that the operating subloop experiences a malfunction. They also allow the operator to start and stop the hydraulic pump motors and manually transfer control from one subloop to the other automatically. Interlocks are provided to minimize the risk of an operator inadvertently shutting down a subloop which is controlling the actuator, or placing a disabled subloop in control of the actuator.

The logic circuits also incorporate interlock circuits which automatically initiate an FCV "lockup" (motion inhibit) and shut down the HPU if any of the following occur:

a. Drywell pressure high.

b. Position demand signal out of range.

c. Actuator velocity excessively high.

d. Rate of change of FCV position excessively high.

e. Actuator oscillating (instability).

f. Hydraulic fluid temperature excessively high.

g. Hydraulic reservoir fluid level excessively low.

Since the above conditions are either potentially damaging to equipment, or caused by malfunction of non-redundant equipment, the logic circuits will not start the alternate subloop.

On the other hand, there are several non-damaging conditions resulting from possible malfunction within redundant circuits. In these cases, if the redundant circuits are operable, the logic circuits will automatically stop the operating subloop, momentarily initiating an FCV "lockup"; start the alternate subloop; and place the alternate subloop in control of the actuator.

These non-damaging conditions are as follows:

a. Prolonged velocity error.

b. Hydraulic pump motor overload or undervoltage.

c. Loss of pump outlet pressure.

d. Hydraulic fluid temperature high, but not damaging.

e. Reservoir fluid level low, but not damaging.

If the alternate subloop is disabled when the above events occur, the logic circuits will shut down the HPU and lock the FCV if the event is disabling (a, b and c above), or allow uninterrupted operation if the event is not disabling (d and e above).

Finally, the logic circuits operate indicators and annunciators to provide information of FCV and HPU status to operating personnel. Information includes whether or not the FCV motion is inhibited, whether or not the redundant subloop is disabled, status of HPU filters, and the like.

It should be noted that for maximum assurance of inhibiting FCV motion, the logic circuits accomplish the following when initiating an FCV "lock-up":

a. Switches analog circuits to lock velocity controller output at mid-range (zero velocity) value.

b. Switches analog circuits to provide zero velocity signal (zero amps) to both servo valves, irrespective of controller output.

c. De-energizes the "operate" solenoids of both subloops solenoid valves.

d. Energizes the "isolate" (lock-up) solenoids of both subloop solenoid valves.

e. Stops both hydraulic pump motors.

f. Inhibits both subloops from being re-started and placed in control until manually re-set.

5.4.1.10 Low-Frequency Motor-Generator (LFMG) Set

5.4.1.10.1 Description

Refer to subsection 7.7.1.3.3.3

5.4.1.10.2 Safety

The LFMG set is nonessential equipment and has no safety function. However, design requirement is that the LFMG set cannot interfere with a recirculation system safety function (e.g., RPT).

5.4.1.10.3 Power Generation

The basic design requirements for the LFMG set are power generation oriented, that is, the purpose of the LFMG set is to prevent cavitation of the flow control valve at low circulation flows while maintaining enough flow to prevent reactor pressure vessel temperature stratification. Thus, most events that cause the recirculation pumps to trip from the main power source will cause the LFMG set to start and pick up the pumps at 25 percent speed to maintain circulation.

5.4.1.11 Power Supplies

5.4.1.11.1 General

The pump motors can be supplied from a nonessential 60-Hz power source through one nonessential breaker and two essential class 1E, Seismic Category I, circuit breakers or from the 15-Hz output of the nonessential LFMG set. Interlocks are provided to prevent powering of the pump motor from both power sources simultaneously. The two class 1E breakers from the 60-Hz power source and the nonessential LFMG set supply and output breakers are used for the RPT system.

The recirculation system power supplies are designed so that no single failure of a power supply can prevent the action of the RPT safety function, nor can the single failure of a power supply prevent the protection of equipment required under the power-generation design-basis.

5.4.1.11.2 Power Supply Arrangement

The arrangement of the various power supplies needed to power the recirculation system is shown in Figure 5.4-33. A single-line diagram of the auxiliary power system showing the recirculation pump motor and LFMG set power supplies, the 120-V ac instrument bus, and the 125-V dc control power to the 4.16 kV and 6.9 kV circuit breakers is presented on Figure 5.4-34.

5.4.2 Steam Generators (PWR)

Subsection 5.4.2 is not applicable to this FSAR.

5.4.3 Reactor Coolant Piping

The reactor coolant piping is discussed in subsection 5.4.1. The recirculation loops are shown in Figures 5.4-1 through 5.4-3. The design characteristics are presented in Table 5.4-1.

5.4.4 Main Steam Line Flow Restrictors

5.4.4.1 Safety Design Bases

The main steam line flow restrictors were designed:

a. To limit the loss of coolant from the reactor vessel following a steam line rupture outside the containment to the extent that the reactor vessel water level remains high enough to provide cooling within the time required to close the main steam line isolation valves

b. To withstand the maximum pressure difference expected across the restrictor, following complete severance of a main steam line

c. To limit the amount of radiological release outside of the drywell prior to MSIV closure

d. To provide trip signals for MSIV closure

5.4.4.2 Description

A main steam line flow restrictor (see Figure 5.4-8) is provided for each of the four main steam lines. The restrictor is a complete assembly welded into the main steam line. It is located upstream of the MSIVs. The restrictor limits the coolant blowdown rate from the reactor vessel in the event a main steam line break occurs outside the containment to the maximum (choke) flow of 6.542×10^6 lb/hr at 992.6 psig upstream pressure. The restrictor assembly consists of a venturi-type nozzle insert welded, in accordance with applicable code requirements, into the main steam line. The flow restrictor is designed and fabricated in accordance with ASME "Fluid Meters," 6th edition, 1971.

The flow restrictor has no moving parts. Its mechanical structure can withstand the velocities and forces associated with a main steam line break. The maximum differential pressure is conservatively assumed to be 1375 psi, the reactor vessel ASME Code limit pressure.

The ratio of venturi throat diameter to steam line inside diameter of approximately 0.5 results in a maximum pressure differential (unrecovered pressure) of about 10 psi at 100 percent of rated flow.

This design limits the steam flow in a severed line to less than 170 percent rated flow, yet it results in negligible increase in steam moisture content during normal operation. The restrictor is also used to measure steam flow to initiate closure of the main steam line isolation valves when the steam flow exceeds preselected operational limits, as well as to measure steam flow for indication and feedwater flow control.

5.4.4.3 Safety Evaluation

In the event a main steam line should break outside the containment, the critical flow phenomenon would restrict the steam flow rate in the venturi throat to 170 percent of the rated value. Prior to isolation valve closure, the total coolant losses from the vessel are not sufficient to cause core uncovering and the core is thus adequately cooled at all times.

Analysis of the steam line rupture accident (see Chapter 15, Accident Analysis) shows that the core remains covered with water and that the amount of radioactive materials released to the environs through the main steam line break does not exceed the guidelines values of published regulations.

[HISTORICAL INFORMATION] [Tests on a scale model determined final design and performance characteristics of the flow restrictor. The characteristics include maximum flow rate of the restrictor corresponding to the accident conditions, unrecoverable losses under normal plant operating conditions, and discharge moisture level. The tests showed that flow restriction at critical throat velocities is stable and predictable.]

The steam flow restrictor is exposed to steam of 1/10 to 2/10 percent moisture flowing at velocities of approximately 150 ft/sec (steam piping ID) to approximately 600 ft/sec (steam restrictor throat). ASTM A351 (Type 304) cast stainless steel was selected for the steam flow restrictor material because it has excellent resistance to erosion-corrosion in a high velocity steam atmosphere. The excellent performance of stainless steel in high velocity steam appears to be due to its resistance to corrosion. A protective surface film forms on the stainless steel which prevents any surface attack and this film is not removed by the steam.

Hardness has no significant effect on erosion-corrosion. For example, hardened carbon steel or alloy steel will erode rapidly in applications where soft stainless steel is unaffected.

Surface finish has a minor effect on erosion-corrosion. If very rough surfaces are exposed, the protruding ridges or points will erode more rapidly than a smooth surface. Experience shows that a machined or a ground surface is sufficiently smooth and that no detrimental erosion will occur.

5.4.4.4 Inspection and Testing

[HISTORICAL INFORMATION] [Because the flow restrictor forms a permanent part of the main steam line piping and has no moving components, no testing program is planned. Only very slow erosion will occur with time, and such a slight enlargement will have no safety significance. Stainless steel resistance to corrosion has been substantiated by turbine inspections at the Dresden Unit 1 facility, which have revealed no noticeable effects from erosion on the stainless steel nozzle partitions. The Dresden inlet velocities are about 300 ft/sec and the exit velocities are 600 to 900 ft/sec. However, calculations show that, even if the erosion rates are as high as 0.004 in. per year, after 40 years of operation the increase in restrictor choked flow rate would be no more than 5 percent. A 5 percent increase in the radiological dose calculated for the postulated main steam line break accident is not significant.]

5.4.5 Main Steam Line Isolation System

5.4.5.1 Safety Design Bases

The main steam line isolation valves, individually or collectively, have been designed to:

a. Close the main steam lines within the time established by design basis accident analysis to limit the release of reactor coolant

b. Close the main steam lines slowly enough that simultaneous closure of all steam lines will not induce transients that exceed the nuclear system design limits

c. Close the main steam line when required despite single failure in either valve or in the associated controls, to provide a high level of reliability for the safety function

d. Use separate energy sources as the motive force to close independently the redundant isolation valves in the individual steam lines

e. Use local stored energy (compressed air and/or springs) to close at least one isolation valve in each steam pipeline without relying on the continuity of any variety of electrical power to furnish the motive force to achieve closure

f. Be able to close the steam lines, either during or after seismic loadings, to assure isolation if the nuclear system is breached

g. Have capability for testing, during normal operating conditions, to demonstrate that the valves will stroke

5.4.5.2 Description

Two isolation valves are welded in a horizontal run of each of the four main steam pipes; one valve is as close as possible to the inside wall of the drywell and the other is just outside the containment.

Each main steam line isolation valve is a 28 in., Y-pattern, globe valve. Rated steam flow rate through each valve is approximately 4.74×10^6 lb/hr. The main disc or poppet is attached to the lower end of the stem. Normal steam flow tends to close the valve, and higher inlet pressure tends to hold the valve closed. The bottom end of the valve stem closes a small pressure balancing hole in the poppet. When the hole is open, it acts as a pilot valve to relieve differential pressure forces on the poppet. Valve stem travel is sufficient to give flow areas past the wide open poppet approximately equal to the seat port area. The poppet travels approximately 90 percent of the valve stem travel to close the main disc, approximately the last 10 percent of travel to close the pilot hole. The air cylinder can open the poppet with a maximum differential pressure of 200 psi across the isolation valve in a direction that tends to hold the valve closed.

A 45-degree angle permits the inlet and outlet passages to be streamlined; this minimizes pressure drop during normal steam flow and helps prevent debris blockage. The pressure drop at 91 percent of rated flow is 6.6 psi maximum. The valve stem penetrates the valve bonnet through a stuffing box that has two sets of replaceable packing. A lantern ring and leak-off drain are located between the two sets of packing. In the original design, the poppet backseats when the valve is fully open to help prevent leakage through the stem packing.

Features to improve MSIV performance and seating capabilities have been incorporated into each of the MSIVs and these features include:

1. Installation of a nose guided/anti-rotation poppet to improve poppet seating and prevent poppet rotation;

2. Installation of a single piece, forged, anti-rotation stem that eliminates the need for threading, pinning and welding required by the original design, and

elimination of the backseat to increase both the strength and guidance of the stem when used with the back seated cover modification (as discussed below);

3. A floating pilot poppet having a 'Stellite' surface to prevent stem wear and preclude the pilot poppet nut from backing out of the pilot poppet; and

4. A cover back seated poppet modification that was developed to eliminate vibration wear on MSIV body internal guides. When used with an anti-rotation stem and poppet, it also eliminates rotational wear. The modification incorporates a ring protruding from the bottom side of the valve cover forging. The valve stem was redesigned to eliminate the back seat such that the poppet will back seat against the bottom of the valve cover when in the open position. Back seating the poppet holds the poppet rigid and stops vibration of the valve internal parts when the valve is open. The direct interface eliminates wear of the body guide ribs, poppet internals and stem. The cover back seated poppet offers the additional advantages of a reduced depth stuffing box to take advantage of the five ring packing set that has become industry standard, live loaded packing and improved stem guidance. A second cover bushing was added in the lower end of the valve cover which guides a larger diameter of the stem when the valve is in the open position. The large diameter combined with the guidance provided by the two bushing arrangement enhances the ability of the stem to resist side loads. The modified cover design retains the two sets of five-ring packing separated by a lantern ring, and the leakoff connection remains active.

The improved design is depicted in Figure 5.4-9, Sheet 2. Attached to the upper end of the stem is an air cylinder that opens and closes the valve and a hydraulic dashpot that controls its speed. The speed is adjusted by a valve in the hydraulic return line bypassing the dashpot piston. Valve closing time is adjustable to between 3 and 10 seconds.

The air cylinder is supported on the valve bonnet by actuator support and spring guide shafts. Helical springs around the spring guide shafts close the valve if air pressure is not available. The motion of the spring seat member actuates switches in 92 percent open, 90 percent open, and 10 percent open valve positions.

The valve is operated by pneumatic pressure and by the action of compressed springs. The control unit is attached to the air cylinder. This unit contains three types of control valves - pneumatic, ac, and ac from another source - that open and close the main valve and exercise it at slow speed. Remote manual switches in the control room enable the operator to operate the valves.

Operating air is supplied to the valves from the instrument air system. An air tank between the control valve and a check valve provides backup operating air.

Each valve is designed to accommodate saturated steam at plant operating conditions, with a moisture content of approximately 0.25 percent, an oxygen content of 30 ppm, and a hydrogen content of 4 ppm. The valves are furnished in conformance with a design pressure and temperature rating in excess of plant operating conditions to accommodate plant overpressure conditions.

In the worst case, if the main steam line should rupture downsteam of the valve, steam flow would quickly increase to 170 percent of rated flow. Further increase is prevented by the venturi flow restrictor inside the containment.

During approximately the first 75 percent of closing, the valve has little effect on flow reduction, because the flow is choked by the venturi restrictor. After the valve is approximately 75 percent closed, flow is reduced as a function of the valve area versus travel characteristic.

The design objective for the valve is a minimum of 40 years service at the specified operating conditions. Operating cycles are estimated to be 100 cycles per year during the first year and 50 cycles per year thereafter.

In addition to minimum wall thickness required by applicable codes, a corrosion allowance of 0.120-in. minimum is added to provide for 40 years service.

Design specification ambient conditions for normal plant operation are 135 F normal temperature, 150 F maximum temperature, 100 percent humidity, a total radiation dose of 17.4 x 10^6 rad for 5-year maintenance life. The inside valves are not continuously exposed to maximum conditions, particularly during reactor shutdown, and valves outside the primary containment and shielding are in ambient conditions that are considerably less severe.

The main steam line isolation valves are designed to close under accident environmental conditions of 340 F for one hour at drywell design pressure. In addition, they are designed to remain closed under the following post-accident environment conditions:

a. 340 F for an additional 2 hours at drywell design pressure of 45 psig maximum

b. 320 F for an additional 3 hours at 15 psig maximum

c. 250 F for an additional 18 hours at 15 psig maximum

d. 200 F during the next 99 days at 15 psig maximum

To resist sufficiently the response motion from the safe shutdown earthquake, the main steam line valve installations are designed as seismic Category I equipment. The valve assembly is manufactured to withstand the safe shutdown earthquake forces applied at the mass center of the extended mass of the valve operator, assuming the cylinder/spring operator is cantilevered from the valve body and the valve is located in a horizontal run of pipe.The stresses caused by horizontal and vertical seismic forces are assumed to act simultaneously. The stresses in the actuator supports caused by seismic loads are combined with the stresses caused by other live and dead loads, including the operating loads. The allowable stress for this combination of loads is based on the allowable stress set forth in applicable codes. The parts of the main steam isolation valves that constitute a process fluid pressure boundary are designed, fabricated, inspected, and tested as required by the ASME Code, Section III.

5.4.5.3 Safety Evaluation

In a direct cycle nuclear power plant, the reactor steam goes to the turbine and to other equipment outside the containment. Radioactive materials in the steam are released to the environs through process openings in the steam system or escape from accidental openings. A large break in the steam system can drain the water from the reactor core faster than it is replaced by feedwater.

The analysis of a complete, sudden steam line break outside the containment is described in Chapter 15, Accident Analyses. The analysis shows that the fuel barrier is protected against loss of cooling if main steam isolation valve closure is within specified limits, including instrumentation delay to initiate valve closure after the break. The calculated radiological effects of the radioactive material assumed to be released with the steam are shown to be well within the guideline values for such an accident.

The shortest closing time (approximately 3 sec) of the main steam isolation valves is also shown in Chapter 15 to be satisfactory. The switches on the valves initiate reactor scram when specific conditions (extent of valve closure, number of pipe lines included, and reactor power level) are exceeded (see subsection 7.2.1). The pressure rise in the system from stored and decay heat may cause the nuclear system relief valves to open briefly, but the rise in fuel cladding temperature will be insignificant. No fuel damage results.

[HISTORICAL INFORMATION] [The ability of this 45-degree, Y-design globe valve to close in a few seconds after a steam line break, under conditions of high pressure differentials and fluid flows with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of dynamic tests. A full-size, 20" valve was tested in a range of steam-water blowdown conditions simulating postulated accident conditions (Ref. 2).

The following specified hydrostatic, leakage, and stroking tests, as a minimum, are performed by the valve manufacturer in shop tests:

a. To verify its capability to close between 3 and 10 sec, each valve is tested at rated pressure (1000 psig) and no flow. The valve is stroked several times, and the closing time is recorded. The valve is closed by spring only and by the combination of air cylinder and springs. The closing time is slightly greater when closure is by springs only.

b. Leakage is measured with the valve seated and backseated. The specified maximum seat leakage, using cold water at design pressure, is 2 cm^3/hr/in. of nominal valve size. In addition, an air seat leakage test is conducted using 50 psi pressure upstream. Maximum permissible leakage is 0.1 scfh/in. of nominal valve size. There must be no visible leakage from either set of stem packing at hydrostatic test pressure. The valve stem is operated a minimum of three times from the closed position to the open position, and the packing leakage still must be zero by visual examination.

c. Each valve is hydrostatically tested in accordance with the requirements of the applicable edition and addenda of the ASME Code. During valve fabrication, extensive nondestructive tests and examinations are conducted. Tests include radiographic, liquid penetrant, or magnetic particle examinations of casting, forgings, welds, hard-facings, and bolts.

d. The spring guides, the guiding of the spring seat member on support shafts, and rigid attachment of the seat member assure correct alignment of the actuating components. Binding of the valve poppet in the internal guides is prevented by making the poppet in the form of a cylinder longer than its diameter and by applying stem force near the bottom of the poppet.

After the valves are installed in the nuclear system, each valve is tested several times in accordance with the preoperational and startup test procedures.]

Two isolation valves provide redundancy in each steam line so either can perform the isolation function, and either can be tested for leakage after the other is closed. The inside valve, the outside valve, and their respective control systems are separated physically.

The design of the isolation valve has been analyzed for earthquake loading. The cantilevered support of the air cylinder, hydraulic cylinder, springs, and controls is the key area. The increase in loading caused by the specified earthquake loading does not result in stresses exceeding ASME allowable, or prevent the valve from closing as required.

Electrical equipment that is associated with the isolation valves and operates in an accident environment is limited to the wiring, solenoid valves, and position switches on the isolation valves. The expected pressure and temperature transients following an accident are discussed in Chapter 15.

5.4.5.4 Inspection and Testing

The main steam isolation valves can be functionally tested for operability during plant operation and refueling outages. The test operations are listed below. During refueling outages the main steam isolation valves can be functionally tested, leaktested, and visually inspected.

The main steam isolation valves can be tested and exercised individually to the 90 percent open position, because the valves still pass rated steam flow when 90 percent open.

The main steam line isolation valves can also be tested and exercised individually to the fully closed position if reactor power is reduced sufficiently to avoid scram from reactor overpressure or high flow through the steam line flow restrictors. In addition, reactor power is administratively limited to less than 75% of rated should closure of a single MSIV be required. Continuous operation with one MSIV out of service is also allowed if reactor power is limited to less than 75%. This limit preserves the integrity of the remaining open MSIVs by preventing the possibility of high flow induced vibration. Reactor operation at greater than 75% of rated with one MSIV closed will cause higher than rated steam flow to pass through the remaining 3 “live” steam lines. Higher than rated steam flow through the remaining operable steam lines could cause excessive flow induced vibration and potentially damage the MSIVs.

Leakage from the valve stem packing will become suspect during reactor operation from measurements of leakage into the drywell, or from observations or similar measurements in the steam tunnel. During shutdown while the nuclear system is pressurized, the leak rate through the inner packing can be measured by collecting and timing the leakage. Leakage through the inner packing would be collected from the packing drain line. The outboard MSIV packing leakage is piped to the radwaste system. Piping and equipment associated with the leakoff line conform to seismic Category I up to and including the packing leakoff valve. If leakage is observed, the valve is manually closed and the outer stem packing of the MSIV is relied upon to prevent leakage.

The leak rate through the pipeline valve seats (pilot and poppet seats) is measured accurately during shutdown as described in Section 6.2.6.

During prestartup tests following an extensive shutdown, the inboard valves will receive the same hydro tests that are imposed on the primary system. The outboard valves will be checked at pressure. The valve closure time is rechecked in accordance with procedures following any work performed on the valve.

Such a test and leakage measurement program ensures that the valves are operating correctly and that a leakage trend is detected.

5.4.6 Reactor Core Isolation Cooling System (RCIC)

5.4.6.1 Design Bases

5.4.6.1.1 Reactor Vessel Water Inventory and Isolation

5.4.6.1.1.1 Residual Heat

When in a normal (standby) alignment, the RCIC system shall initiate and discharge a specified constant flow into the reactor vessel over a specified pressure range within a 30-second time interval. The RCIC water discharged into the reactor vessel via one of the main feedwater lines varies between a temperature of +65 F up to and including a temperature of 140 F. The water temperature lower limit of +65 F is maintained through administrative controls for fracture prevention of the train "B" feedwater flued head. A water temperature lower limit of +40 F is applicable for all remaining considerations. The RCIC water replenishes reactor vessel inventory to permit adequate core cooling to take place.

In the event of a station blackout, the RCIC system is relied upon to provide adequate water inventory to the reactor coolant system to remove decay heat, depressurize the reactor, and maintain reactor vessel level above the top of the active fuel (Ref. 3). The GGNS response to a station blackout event is provided in Appendix 8A.

Redundantly, the HPCS system performs the same function, hence, providing single-failure protection. Both systems use different electrical power sources of high reliability, which permits operation with either onsite power or offsite power. Additionally, the RHR system performs a residual heat removal function.

The RCIC system design includes interfaces with redundant leak detection devices namely:

a. A high pressure drop across a flow device in the steam supply line equivalent to 300 percent of the steady state steam flow at 1192 psia

b. A high area temperature, utilizing temperature switches as described in the leak detection system. High area temperature is alarmed in the control room.

c. A low reactor pressure of 50 psig minimum

d. A high pressure between the turbine exhaust rupture diaphragms

These devices, activated by the redundant power supplies, automatically isolate the steam supply to the RCIC turbine.

Other isolation bases are defined in subsection 5.4.6.1.1.2. Again HPCS provides redundancy for RCIC should RCIC become isolated, hence, providing single-failure protection.

5.4.6.1.1.2 Isolation

The RCIC P&ID is given in Figures 5.4-10 and 5.4-11. There are five RCIC pipe lines that have a low design pressure and therefore require relief devices or some other basis for addressing overpressure protection. They are:

1. RCIC pump suction line

2. RCIC turbine exhaust line

3. Portions of the RCIC pump discharge to CST line

4. Portions of the RCIC minimum flow line

5. Portions of the RCIC turbine lube oil cooling water line

The design pressure of the other major pipe lines is equal to the vessel design pressure and subject to the normal overpressure protection system.

Isolation valve arrangements include the following:

a. One RCIC line penetrates the coolant pressure boundary for the reactor. This is the RCIC steam line which branches off the main steam line "A" between the reactor vessel and the inboard main steam isolation valve. This line has two automatic motor operated isolation valves. One is located inside and the other outside containment. An automatic motor operated inboard RCIC isolation valve bypass valve is also provided. The isolation signals noted earlier close these valves.

b. Deleted

c. The RCIC turbine exhaust line vacuum breaker system line has two automatic motor operated valves and two check valves. This line runs between the suppression pool air space and the turbine exhaust line downstream of the exhaust line check valve. Positive isolation requires concurrent drywell high pressure and RCIC steam supply pressure-low signals to isolate.

   The vacuum breaker valve complex is placed outside containment due to a more desirable environment. In addition, the valves are readily accessible for maintenance and testing.

d. The RCIC pump suction line, minimum flow pump discharge line, and turbine exhaust line all penetrate the containment and are submerged in the suppression pool. The isolation valves for these lines are all outside containment and are provided with remote-manual operation. The turbine exhaust line motor operated valve is also provided with an automatic isolation that requires concurrent drywell high pressure and RCIC steam supply pressure-low signals to isolate.

The sparger pipe in Figure 5.4-10 is installed to reduce oscillations in the exhaust line associated with the formation and the collapse of steam bubbles in the suppression pool. The

20-inch swing check valve has a lever and a counterweight to balance the disc so that it will remain open at low flow conditions.

Two safety grade check valves (F065 and F204) and a motor operated isolation valve (F013) (normally closed) separate the RCIC pump suction line from reactor pressure. A relief valve (PSV-F017) is located on the pump suction line to accommodate any potential leakage from the isolation valves. A high pump suction pressure alarm is also provided in the control room.

The RCIC turbine exhaust line is vented to the suppression pool and is not subject to reactor pressure during normal operation. Rupture discs (D001, D002) are installed on this line to prevent exceeding piping pressure. The RCIC system will automatically isolate if the rupture discs were to blow open.

Portions of the RCIC pump discharge to CST line are vented to atmosphere, and in stand-by condition are separate from main feedwater line pressure by the pump discharge isolation valves (F013, F065) and two additional normally closed isolation valves (F022, F059). The two additional isolation valves provide high/low pressure separation when the RCIC system is injecting the vessel.

Portions of the RCIC minimum flowline are vented to the suppression pool and, again, separated from reactor pressure by the pump discharge isolation valves (F013 and F065) and one additional normally closed isolation valve (F019).

Portions of the RCIC turbine lube oil cooling water line, in the stand-by condition, are separated from reactor pressure by the pump discharge isolation valves and one additional normally closed shut-off valve (F046). During system operation a relief valve (F018) is provided to prevent overpressurizing piping, valves, and equipment in the coolant loop in the event of failure of pressure control valve E51-F015.

If the steam isolation valves were temporarily closed for maintenance, administrative control and specific operating procedures preclude the possibility of thermal shock or water hammer to the steam line, valve seats, and discs. Keylock switches are provided as part of the administrative control. Operating procedures involve opening the outboard isolation valve, warming the steam line by throttling open the warmup valve located on a pipeline bypassing the inboard isolation valve and then opening the inboard isolation valve.

A vacuum breaker system is installed close to the RCIC turbine exhaust line suppression pool penetration to avoid siphoning water from the suppression pool into the exhaust line as steam in the line condenses during and after turbine operation. The vacuum breaker line runs from the suppression pool air volume to the RCIC exhaust line through two normally open, motor-operated gate valves and two swing check valves arranged to allow air flow into the exhaust line, precluding steam flow to the suppression pool air volume.

5.4.6.1.2 Reliability, Operability, and Manual Operation

5.4.6.1.2.1 Reliability and Operability (Also see subsection 5.4.6.2.4)

The RCIC system as noted in Table 3.2-1 is designed commensurate with the safety importance of the system and its equipment. Each component is individually tested to confirm compliance with system requirements. The system as a whole is tested during both the startup and pre-operational phases of the plant to set a base mark for system reliability. To confirm that the system maintains this mark, functional and operability testing is performed at predetermined intervals throughout the life of the reactor plant.

The RCIC electrohydraulic system integrated with the turbine governing valve is of a safety-grade design. The entire turbine assembly has been tested for seismic qualification in accordance with IEEE 344-1975. The electrohydraulic system was in its operational modes during the test program.

A design flow functional test of the RCIC system may be performed during normal plant operation by drawing suction from the condensate storage tank and discharging through a full flow test return line to the condensate storage tank. The discharge valve to the main feedwater line remains closed during the test, and reactor operation remains undisturbed. All components of the RCIC system are capable of individual functional testing during normal plant operation. Control system design provides automatic return from test to operating mode if system initiation is required. There are three exceptions: 1. Auto/ manual initiation on the flow controller. This feature is required for operator flexibility during system operation.2.Steam inboard/

outboard isolation valves. Closure of either or both of these valves requires operator action to properly sequence their opening. An alarm sounds when either of these valves leaves the fully open position. 3. Other bypassed or otherwise deliberately rendered inoperable parts of the system are automatically indicated in the control room at the system level. Capability for manual initiation of system level indication exists for items not readily automated.

5.4.6.1.2.2 Manual Operation (Also see subsections 5.4.6.2.5.2 and .3)

In addition to the automatic operational features, provisions are included for remote-manual startup, operation, and shutdown of the RCIC system, provided initiation or shutdown signals do not exist.

5.4.6.1.3 Loss of Offsite Power

The RCIC system power is derived from a highly reliable source that is maintained by either onsite or offsite power. (Refer to subsection 5.4.6.1.1.) This system could be operated if all alternating current power is lost; however, this condition represents more than a single-failure condition. Since the system utilizes steam power for the turbine and direct current power sources for the control instrumentation, the system will operate as long as both are available. The dc power system is designed to operate without the help of chargers for 4 hours.

The ampere-hour capacity of the batteries that provide power for RCIC control is shown on Figure 8.3-10.

5.4.6.1.4 Physical Damage

The system is designed to the requirements of Table 3.2-1 commensurate with the safety importance of the system and its equipment. The RCIC is physically located in a different quadrant of the auxiliary building and utilizes different divisional power (and separate electrical routings) than the HPCS system (subsection 5.4.6.1.1). (Also see subsection 5.4.6.2.4.)

5.4.6.1.5 Environment

The system operates for the time intervals and the environmental conditions specified in Section 3.11.

5.4.6.2 System Design

5.4.6.2.1 General

5.4.6.2.1.1 Description

The reactor core isolation cooling (RCIC) system consists of a turbine, pump, piping, valves, accessories, and instrumentation designed to assure that sufficient reactor water inventory is maintained in the reactor vessel to permit adequate core cooling to take place. This prevents reactor fuel overheating during the following conditions:

a. Should the vessel be isolated and maintained in the hot shutdown condition

b. Should the vessel be isolated and accompanied by loss of coolant flow from the reactor feedwater system

c. Should a complete plant shutdown under conditions of loss of normal feedwater system be started before the reactor is depressurized to a level where the shutdown coolant system can be placed into operation

Following a reactor scram, steam generation will continue at a reduced rate due to the core fission product decay heat. At this time the turbine bypass system will divert the steam to the main condenser, and the feedwater system will supply the make-up water required to maintain reactor vessel inventory.

In the event the reactor vessel is isolated and the feedwater supply is unavailable, relief valves are provided to maintain automatically (or remote manually) vessel pressure within desirable limits. The water level in the reactor vessel will drop due to continued steam generation by decay heat.

Upon reaching a predetermined low level, the RCIC system is initiated automatically. The turbine driven pump will supply makeup water from the suppression pool; however, RCIC is normally lined up to the condensate storage tank (CST) for water quality concerns and will automatically switch to the suppression pool on a CST low level or suppression pool high level. The turbine will be driven with a portion of the decay heat steam from the reactor vessel, and will exhaust to the suppression pool. Note: Suppression pool water should be used only in the event all sources of demineralized water have been exhausted.

During RCIC operation, the suppression pool acts as the heat sink for steam generated by reactor decay heat. This will result in a rise in pool water temperature. Heat exchangers in the residual heat removal system are used to maintain pool water temperature within acceptable limits by cooling the pool water directly.

During RCIC turbine standby conditions, condensate buildup in the turbine exhaust line is minimized by the installation of a drain pot in a low point of the line near the turbine exhaust connection. The condensate collected in the drain pot drains to the radwaste through a restricting orifice.

5.4.6.2.1.2 Diagrams

The following diagrams are included for the RCIC systems:

a. Schematic piping and instrumentation diagrams (Figures 5.4-10 and 5.4-11) show components, piping, points where interface system and subsystems tie together, and instrumentation and controls associated with subsystem and component actuation.

b. Schematic process diagrams (Figures 5.4-12 and 5.4-13) show temperature, pressures, and flows for RCIC operation and system process data hydraulic requirements.

5.4.6.2.1.3 Interlocks

The following define the various electrical interlocks:

a. There are two keylocked valves, namely F063 and F064, and two keylocked resets, namely the isolation resets.

b. F031 will not open until F022 and F059 limit switches actuate at the fully closed valve position.

c. F068's limit switch activates when fully open and clears F045/F095 permissive so F045/F095 can open.

d. F045's limit switch activates when F045 is not fully closed which initiates startup ramp function. This ramp resets each time F045 is closed. F045's limit switch activates when F045 is fully open to close F095.

e. F045's limit switch activates when fully closed and permits F004, F005, F025, and F026 to open and closes F013 and F019.

f. The turbine trip throttle valve (part of C002) limit switch activates when fully closed and closes F013 and F019.

g. High turbine exhaust pressure, low pump suction pressure, the combined signals of F045 fully open plus reactor high water level or an isolation signal actuates and closes the turbine trip throttle valve. When signal is cleared, the trip throttle valve must be reset from control room.

h. 120 percent overspeed trips both the mechanical trip at the turbine and the trip throttle valve. The former is reset at the turbine and then the latter is reset in the control room.

i. An isolation signal closes F031, F063, F064, F076, and other valves as noted above in items f. and g. Also F068 closes with concurrent drywell high pressure and RCIC steam supply pressure - low signals.

j. An initiation signal opens F010, F013, and F046 if closed; starts gland seal system; and closes F022 and F059 if open. The initiation signal also opens F095 and following approximately a 6 second time delay F045 opens.

k. High and low inlet RCIC steam line drain pot levels, respectively, open and close F054.

l. The combined signal of low flow plus pump discharge pressure opens and with increased flow closes F019. Also see items e. and f. above.

RCIC motor operated valve F063 and its position indication circuitry are powered from the Division 2 power source; F064 and its position indication circuitry are powered from the Division 1 power source.These valves are normally open, powered to close, with the power and position indication from the same division as each valve. Redundancy exists between each valve.

The isolation signal is automatic and bypasses the keylock when valves F063 and F064 must be closed in the case of an RCIC line break. For other accidents it is more desirable to have steam available for RCIC operation than to preclude its operation because of a containment automatic isolation valve closure signal. If the isolation valves were closed, operator action would be required to reopen the valves to avoid water hammer and thermal shock. An isolation signal is given for a large pipe break by detecting flow rates greater than 300 percent of the steady-state steam flow. For leakage with flow rates less than 300 percent of steady-state steam flow, an isolation signal is signaled by use of area temperature sensors provided by the leak detection system.

5.4.6.2.2 Equipment and Component Description

5.4.6.2.2.1 Design Conditions

The pressures for the components of the RCIC system, defined below, are shown in Figures 5.4-12 and 5.4-13.

a. One 100 percent capacity turbine and accessories

b. One 100 percent capacity pump assembly and accessories

c. Piping, valves, and instrumentation for:

    1. Steam supply to the turbine

    2. Deleted

    3. Turbine exhaust to the suppression pool

    4. Make-up supply from the condensate storage tank to the pump suction

    5. Make-up supply from the suppression pool to the pump suction

    6. Deleted

    7. Pump discharge to the main feedwater line, including a test line to the condensate storage tank, a minimum flow bypass line to the suppression pool, and a coolant water supply to accessory equipment

The basis for the design conditions was the ASME Code, Section III.

5.4.6.2.2.2 Design Parameters

Design parameters for the RCIC system components are listed below. See Figures 5.4-10 and 5.4-11 for cross-reference of component numbers listed below:

a. RCIC pump operation (C001)

Flow Rate	Injection flow - 800 gpm Cooling water flow - 16 to 25 gpm Total pump discharge - 825 gpm (Includes no margin for pump wear)
Water temperature range	40 F to 140 F
NPSH available	24 ft minimum based on pump maximum design flow of 825 gpm, maximum suppression pool water temperature of 140 F, minimum suppression pool water level at elevation 107' 6" (minimum drawdown level conservatively assumed), and suction strainer differential pressure corresponding to the strainers fully loaded (i.e., conservatively specified debris loading resulting from LOCA-generated and pre-LOCA debris materials). The NPSH required for this flow is 18 feet.
Developed head	2980 ft at 1192 psia reactor pressure 610 ft at 165 psia reactor pressure

BHP, not to exceed	925 HP at 2980 feet developed head 175 HP at 610 feet developed head	
Design pressure	1500 psig	
Design temperature	40 F to 140 F	

b. RCIC turbine operation (C002)	<u>H. P. Condition</u>	<u>L. P. Condition</u>
Reactor Press (sat. temp.)	1192 psia	165 psia
Steam inlet pressure	1177 psia	150 psia
Turbine exhaust press	15 to 25 psia	15 to 25 psia
Design inlet pressure	1250 psig @ saturated temperature	
Design exhaust pressure	165 psig @ saturated temperature	

c. RCIC orifice sizing

Minimum flow orifice (D005)	Size for 95 gpm with MO-F019 fully open with the turbine/ pump at minimum speed
Test return orifice (D006)	Size with piping arrangement to simulate pump discharge pressure required when the RCIC system is injecting design flow with the reactor vessel pressure at 165 psia. Valve E51-F551 must be throttled for system testing at a simulated 1015 psia reactor pressure.

Leak-off orifices (D008, D010)	Size for 1/8 inch diameter minimum, 3/16 inch diameter maximum
Steam exhaust drain minimum, pot orifice (D004)	Size for 1/8 inch diameter 3/16 inch diameter maximum
Steam supply bypass orifice (D016)	Size for 1/2 inch nominal
Flow element (N001)	
Medium measured:	Water (assumed pure)
Flow at full meter differential pressure:	1000 gpm
Full meter differential pressure:	345" water at 68 F
Normal flow:	800 gpm
Normal temperature:	40 to 170 F
System design pressure/ temperature:	1500 psig/140 F
Maximum unrecoverable loss at normal flow:	4.5 psi
Installed accuracy:	±1 percent at normal flow and normal temperature
Associated pipe size:	6" Schedule 120

Cooling loop inlet and backpressure orifices (D021 and D012)	Inlet orifice (D021) is sized so that (with the cooler pressure relief valve) low pressure piping is not overpressurized in the event of an inlet pressure regulating valve failure. The outlet orifice (D012) is sized to maintain 16 to 25 gpm to lube oil cooler based upon suction line pressure varying from minimum NPSH value to maximum operating suction pressure with full CST and minimum system flow.
Accuracy	
Combined accuracy of flow element N001,flow transmitter N003 and flow indicator R600:	±2.5 percent maximum
Combined accuracy of the pressure transmitter N004, and pressure indicator R001:	±2.5 percent maximum

d. Valve operation requirements

Steam supply valve (F045)	Open and/or close against maximum expected differential pressure (GGNS-MS-25.0) within 15 seconds
Steam supply bypass valve (F095)	Open and/or close against maximum expected differential pressure (GGNS-MS-25.0) within 5 seconds

Pump discharge valve (F013)	Open and/or close against maximum expected differential pressure (GGNS-MS-25.0) within 15 seconds
Pump minimum flow bypass valve (F019) seconds	Open and/or close against maximum expected differential pressure (GGNS-MS-25.0) within 5
RHR and RCIC Steam supply isolation valves (F063 & F064)	Open and/or close against maximum expected differential pressure (GGNS-MS-25.0)
Cooling water pressure control valve (F015)	Self-contained downstream sensing control valve capable of maintaining constant downstream pressure of 125 psia. Diaphragm of pressure control valve is of the elastomer type.
Pump suction relief valve (F017)	75 psig relief setting; 10 gpm at 10 percent accumulation
Cooling water relief valve (F018)	Size to prevent over pressurizing piping, valves, and equipment in the coolant loop in the event of failure of pressure control valve F015
Pump test return valve (F022)	Will open and/or close against maximum expected differential pressure (GGNS-MS-25.0)
Pump suction valve, suppression pool (F031)	Is capable of opening and closing against maximum expected differential pressure (GGNS-MS-25.0)

Outboard check valve (F065)	Is accessible during plant operation and shall be capable of local testing.
Pump test return control valve (F551)	Capable of throttling control against differential pressures up to 1100 psi
Turbine exhaust maximum expected differential pressure (F068)	Opens and/or closes against isolation valve (GGNS-MS-25.0) at a temperature of 330 F. Physically located in the line on a horizontal run, as close to the containment as practical. With a maximum closing time within the time identified in Appendix 16B
Isolation valve, steam maximum warmup line (F076)	Opens and/or closes against expected differential pressure (GGNS-MS-25.0) with a maximum closing time within the time identified in the Technical Requirements Manual (TRM)
Vacuum breaker against isolation valves (F077/F078)	Valves open and/or close maximum expected differential pressure (GGNS-MS-25.0) with a maximum closing time within the time identified in the Technical Requirements Manual (TRM)
Vacuum breaker check valves (F079/F081)	Valves are full flow and open with a minimum pressure drop (approximately 0.8 psi) across them.

Steam exhaust drain pot system isolation (F004 & F005)	These valves operate only when RCIC system is shut down. They allow drainage to DRW system. They must operate against a differential pressure of 75 psi.
Condensate storage tank isolation valve (F010)	This valve isolates the condensate storage tank so that suction may be drawn from the suppression pool. Valve must operate against maximum expected differential pressure (GGNS-MS-5.0).
Steam inlet drain pot system isolation (F025 & F026)	These valves allow for drainage of the steam inlet drain pot. They must operate against a differential pressure of 1177 psi.
Steam inlet trap bypass valve (F054)	This valve bypasses the trap D003. It must operate against a differential pressure of 1177 psi.
Cooling loop shut off valve (F046)	This valve allows water to be passed through the auxiliary equipment coolant loop. It must operate against maximum expected differential pressure (GGNS-MS-25.0)
Pump test return valve (F059)	This valve allows water to be returned to the condensate storage tank during RCIC system test. It must operate against maximum expected differential pressure (GGNS-MS-25.0)

Thermal relief valve (F090)	1500 psig relief setting; size as required to protect the discharge line between valves F022 and F059 from thermal expansion due to abnormal ambient temperature of 212 F and water at 40 F
e. Rupture disc assemblies (D001 & D002)	Utilized for turbine casing protection, includes a mated vacuum support to prevent rupture disc reversing under vacuum conditions.
Rupture pressure	128 psig to 157.5 psig at 212 F
Flow capacity	75,000 lb/hr at 165 psig

f. Condensate storage requirements

The CST level is normally maintained above 25 ft and has a low level alarm at 22 ft. Standpipes inside the CST ensure that the non-safety systems cannot draw the CST below an 18.9 ft indicated level. The remainder of the CST volume is reserved specifically for RCIC and HPCS.
As described in the PUSAR Section 2.3.5, during implementation of extended power uprate the SBO analysis showed larger volume requirements necessary for maintaining adequate reactor coolant system inventory to assure the core is cooled for the entire coping duration. However, this increased volume requirement is already available with the configuration of existing standpipes in the CST (Ref. 3).

g. RCIC piping water temperature

The maximum water temperature range for continuous system operation will not exceed 140 F. However, due to potential short term operation at higher temperatures, piping expansion calculations are based on 170 F. Administrative controls prevent the RCIC water supply temperature from falling below +65 F to ensure that train B of the feedwater system will not experience service temperatures of less than +65 F.

h. Deleted

i. Ambient conditions of RCIC in the auxiliary building

	Temperature	Relative Humidity
Normal plant operation	60 to 122 F	20 to 90%
Isolation conditions (0-6 hrs)	212 F	100%
Abnormal conditions (6-12 hrs)	150 F	90%

j. Suction strainer sizing

The suppression pool suction strainer shall be sized such that:

1. Pump NPSH requirements are satisfied when the strainer is fully loaded (i.e., conservatively specified debris loading resulting from LOCA-generated and pre-LOCA debris materials).

2. Particles over 0.10 in. diameter are restrained from passage into the pump.

k. Instrument set points

Item	N659	N653	N656 A,E	N010
Service	Pump discharge	Pump suction	TB stm. exh.	TB Steam Inlet
Drain				Pot High
Set point (INC)	175 gpm	NA	25 psig	0" see Note (1)
Set point (DEC)	NA gpm	6.5 in. hg vac	NA	NA
Reset dead band	5%	5 in. hg vac	10 psig	0.5 in.
Required accuracy	±5% of set point	±5% of set point	±5% of set point	±0.25 in.

Note (1) Located mid-range on drain pot

Item	N655 A,B, E,F	N650	N652	N654
Service	TB exh diaphragm	Pump discharge	Pump suction	Pump suction
Set point (INC)	10 psig	125 psig	60 psig	NA
Set point (DEC)	NA	NA	NA	5 psig
Reset dead band	5 psig	25 psig	5 psig	5 psig
Required accuracy	30% of set point	5% of set point	5% of set point	5% of set point

Item	N635A, E	Suppression Pool
Service	Condensate Storage Tank Low Level	Tank Low Level
Set point (INC)	NA	5.9 in. see Note (2)
Set point (DEC)	4.0 ft	
Reset dead band	0.24 ft	0.5 in.
Required accuracy	0.1 ft	± 0.2 in.

Note (2) 1.9 in. above normal water level.

Item	N037
Service	TB Steam Exhaust Drain Pot High
Set point (INC)	0 in. see Note (1)
Set Point (DEC)	NA
Reset dead band	

Required accuracy	± 0.25 in.	0.5 in

l. RCIC system actuation and isolation instrumentation trip setting and set point ranges are provided in Technical Requirements Manual (TRM). To minimize the potential for inadvertent isolation, the RCIC is tested to verify that these set points are properly set.

5.4.6.2.3 Applicable Codes and Classifications

The RCIC system components within the drywell up to and including the outer isolation valve are designed in accordance with ASME Code, Section III, Class 1, Nuclear Power Plant Components. The RCIC system is also designed as seismic Category I equipment.

The reactor core isolation cooling system component classifications and those for the condensate storage system are given in Table 3.2-1.

5.4.6.2.4 System Reliability Considerations

To ensure that the RCIC will operate when necessary and in time to prevent inadequate core cooling, the power supply for the system is taken from immediately available energy sources of high reliability. Added assurance is given in the capability for periodic testing during station operation. Evaluation of reliability of the instrumentation for the RCIC shows that no failure of a single initiating sensor either prevents or falsely starts the system. Operation of the RCIC system in the event of loss of offsite power is discussed in subsection 5.4.6.1.

[HISTORICAL INFORMATION] [Based on a review of past (pre-1986) operating experience, General Electric identified several areas where design changes would improve the reliability and availability of the RCIC turbines. These design changes have been incorporated in the Grand Gulf plant.]

In order to ensure HPCS or RCIC availability for the operational events noted previously, certain design considerations are utilized in design of both systems.

a. Physical independence. The two systems are located in separate areas in different integral rooms of the auxiliary building. Piping runs are separated, and the water delivered from each system enters the reactor vessel via different nozzles.

b. Prime mover diversity and independence. Prime mover independence is achieved by using a steam turbine to drive the RCIC and an electric motor driven pump for the HPCS system.

c. Control independence. Control independence is secured by using different battery systems to provide control power to each unit. Separate detection initiation logics are also used for each system.

d. Environmental independence. Both systems are designed to meet Safety Class 1 requirements. Environment in the equipment rooms is maintained by separate auxiliary systems.

e. Periodic testing. A design flow functional test of the RCIC is performed during plant operation by taking suction from the condensate storage tank and discharging through the full flow test return line back to the condensate storage tank. The discharge valve to the main feedwater line remains closed during the test, and reactor operation is undisturbed.All components of the RCIC system are capable of individual functional testing during normal plant operation. Control system design provides automatic return from test to operating mode if system initiation is required. The three exceptions are as follows:

    1. The auto/manual station on the flow controller. This feature is required for operator flexibility during system operation.

    2. Steam inboard/outboard isolation valves. Closure of either or both of these valves requires operator action to sequence their opening properly.An alarm sounds when either of these valves leaves the fully open position.

    3. Bypassed or other deliberately rendered inoperable parts of the system are automatically indicated in the control room.

Although the full flow test return valves will automatically close when a RCIC initiation occurs, their closure time is such that full isolation of the test return path may require up to 50 seconds.

Additionally, all components of the RCIC system are capable of individual functional testing during normal plant operation.

f. General. Periodic inspections and maintenance of the turbine pump are conducted in accordance with an approved maintenance program, commensurate for nuclear standby service, that takes into consideration the following factors: the manufacturers' recommendations, Terry Turbine User Group recommendations, EPRI guidance, system run time, calendar time, and the GGNS comprehensive maintenance inspection program. Valve position indication and instrumentation alarms are displayed in the control room.

g. To preclude water hammer effects at the pump discharge, the discharge line is maintained in a filled condition. The static head provided by the condensate storage tank, the primary source of RCIC water, will maintain the discharge piping filled up to the injection valve, E51-F013.

5.4.6.2.5 Operation Modes of RCIC System

5.4.6.2.5.1 Automatic Mode

Automatic startup of the RCIC system due to an initiation signal from reactor low water level requires NO operator action. To permit this automatic operation, steps must be taken to prepare the system for standby mode in accordance with System Operating Instructions (SOIs).

There are two trips for the turbine, namely a solenoid operated trip and mechanical overspeed trip.The overspeed trip must be reset out of the control room at the turbine itself. Once the overspeed trip is reset or if only a solenoid trip occurred, the trip throttle valve must be reset. (See Figures 5.4-10 and 5.4-11 for component identification.)

5.4.6.2.5.2 Test Loop Mode

This operating mode is manually initiated by the operator and is utilized during surveillance and retest conditions as described in subsection 5.4.6.2.4.e.

PAGE DELETED

5.4.6.2.5.3 Deleted

5.4.6.2.5.4 Limiting Single Failure

The most limiting single failure in the combined RCIC and HPCS system is the failure of HPCS. If the capacity of RCIC system is adequate to maintain reactor water level, the operator follows subsection 5.4.6.2.5.1. If, however, the RCIC capacity is inadequate, subsection 5.4.6.2.5.1 applies, but additionally the operator may also initiate the ADS system described in Section 6.3.

5.4.6.3 Performance Evaluation

The analytical methods and assumptions in evaluating the RCIC system are presented in Chapter 15, Accident Analyses, and Appendix 15A to Chapter 15, Plant Nuclear Safety Operational Analyses. The RCIC system provides the flows required from the analysis (see Figures 5.4-12 and 5.4-13) within a 30 second interval based upon considerations noted in subsection 5.4.6.2.4.

5.4.6.4 Preoperational Testing

The preoperational and initial startup test program for the RCIC system is presented in Chapter 14, Initial Test Program.

5.4.6.5 Safety Interfaces

The balance of plant-GEH nuclear steam supply system safety interfaces for the reactor core isolation cooling system are: (1) preferred water supply from the condensate storage tank; (2) all associated wire, cable, piping, sensors, and valves which lie outside the nuclear steam supply system scope of supply; and (3) solenoid actuated valve(s).

5.4.7 Residual Heat Removal System

5.4.7.1 Design Bases

The RHR system is comprised of three independent loops, each loop contains its own motor-driven pump, piping, valves, instrumentation and controls. Each loop has a suction source from the suppression pool and is capable of discharging water to the reactor vessel via a separate nozzle, or back to the suppression pool via a full flow test line. In addition, the A and B loops have heat exchangers which are cooled by the standby service water system. Loops A and B can also take suction from the reactor recirculation system suction or fuel pool, and can discharge into the reactor via the feedwater line, LPCI injection lines, fuel pool cooling discharge, or to the containment spray spargers. A separate auxiliary cooling loop is included in the RHR system with its own pumps, heat exchangers, and controls. Piping in the RHR A, B and C loops is utilized for suction and discharge paths. Cooling water for this auxiliary cooling loop is provided by the plant service water system.

5.4.7.1.1 Functional Design Basis

The RHR system has five subsystems, each of which has its own functional requirements. Each subsystem shall be discussed separately to provide clarity.

5.4.7.1.1.1 Residual Heat Removal Mode (Shutdown Cooling Mode)

a. The functional design basis of the shutdown cooling mode is to have the capability to remove decay and sensible heat from the reactor primary system so that the reactor outlet temperature is reduced to 125 F, 20 hours after the control rods have been inserted, to permit refueling when the maximum service water temperature is 90 F, the core is "mature," and the tubes are completely fouled. Following EPU, a longer time is required for reactor cool down as a result of higher decay heat. The shutdown cooling analysis determined that the time required for cooling the reactor to 125°F during normal reactor shutdown, with two loops in service, has increased from 10.6 hours to approximately 16.4 hours at EPU conditions which still meets the 20 hour criterion (Ref. 3). This increase may have an impact on plant availability, however, it has no impact on plant safety or design operating margins. (See subsection 5.4.7.2.2 for exchanger design details.)

b. The design basis for the most limiting single failure for the RHR system (shutdown cooling mode) is that one exchanger loop is lost and the plant is then shut down using the capacity of a single RHR heat exchanger and related service water capability. The shutdown cooling capability at EPU conditions was evaluated using a single heat exchanger loop of RHR with a standby service water temperature of 90°F and a power level of 102%. As described in Section 8.8.4.4.3 of the PUSAR, the shutdown cooling analysis showed that the reactor can be cooled to 212°F in 8.2 hours following insertion of the control rods using one loop of the RHR system.

5.4.7.1.1.2 Fuel Pool Cooling Assistance

The RHR system can be aligned to assist the Fuel Pool Cooling and Cleanup System in removing decay heat. The functional design basis for the fuel pool cooling assistance mode is that RHR pumps A and/or B are used to pump water from the Fuel Pool Cooling and Cleanup (FPCCU) System through the RHR heat exchangers, and back to the FPCCU system. Additional details of this mode are provided in subsection 9.1.3.3. This mode of RHR can be operated in conjunction with Shutdown Cooling Mode when the reactor is shutdown, the vessel head is removed, the transfer canal tube is open and gates removed, and the upper containment pool has been flooded up.

5.4.7.1.1.3 Low Pressure Injection (LPCI) Mode

The functional design bases for the LPCI mode is to pump at a total rate of 22,000 gpm of water by using three separate pump loops from the suppression pool into the core region of the vessel, when the vessel pressure is 20 psid over drywell pressure. Injection flow commences at 225 psid vessel pressure above drywell pressure.

The initiating signals are: vessel level 16.4 inches above the active core or drywell pressure greater than or equal to 2.0 psig. The pumps will attain rated speed in 27 seconds and injection valves fully open in 30 seconds after receipt of the reactor vessel low pressure permissive.

5.4.7.1.1.4 Suppression Pool Cooling Mode

The functional design basis for the suppression pool cooling mode is that it shall have the capacity to ensure that anytime after the blowdown the suppression pool temperature shall not exceed the design value of 210°F. The EPU alternate shutdown cooling analysis of the design basis loss of coolant accident assumed single failure of one of the two RHR heat exchangers and determined the peak bulk suppression pool temperature of 198°F. Therefore, the original suppression pool design temperature limit of 185°F was raised to 210°F. (Ref. 3).

5.4.7.1.1.5 Containment Spray Cooling Mode

The functional design basis for the containment spray cooling mode is that there should be two redundant means to spray into the containment and suppression pool vapor space to reduce internal pressure to below design limits with bypass leakage from all leakage paths from drywell to containment of 0.9 ft, $A/\sqrt{k}$.

5.4.7.1.1.6 Deleted

5.4.7.1.2 Design Basis for Isolation of RHR System from Reactor Coolant System

The low pressure portions of the RHR system are isolated from full reactor pressure whenever the primary system pressure is above the RHR system design pressure. (See subsection 5.4.7.1.3 for further details.) In addition, automatic isolation may occur for reasons of vessel water inventory retention which is unrelated to line pressure rates. (See subsection 5.2.5 for an explanation of the leak detection system and the isolation signals.)

The RHR pumps are protected against damage from a closed discharge valve by means of automatic minimum flow valves.

The minimum flow valves shall automatically open if the pumps are running and the main line flow is less than the low flow trip setpoint. The minimum flow valves will close at flows above the low flow trip reset. Flow modeling analysis has shown that the minimum flow restricting orifices limit bypass flow such that required injection flow is available even if the valves fail to close.

All valves performing an isolation function between the high-pressure and low-pressure boundary in the RHR system are leak rate tested to the requirements of the ASME OM Code for Operation and Maintenance of Nuclear Power Plants.

The minimum flow valve controls meet IEEE-279 requirements on the ECCS network level.

The minimum flow line restricting orifice is Quality Group B (i.e., seismic Category I, ASME Code Section III).

5.4.7.1.3 Design Basis for Pressure Relief Capacity

Discharge lines of the RHR system pressure relief valves are routed so that they are continuously sloping toward the suppression pool. Therefore, there will not be any water accumulation in the discharge lines. These relief lines have been stress analyzed and are capable of taking the seismic and dynamic blowdown loads without loss of piping integrity.

The relief valves in the RHR system are sized on one of three bases:

a. Thermal relief only

b. Valve bypass leakage only

c. Control valve failure and the subsequent uncontrolled flow which results

The intent of the relief valve sizing is to comply with ASME III, Section NC 7000. Transients are treated by items a. and c.; item b. above has resulted from an excessive leak past isolation valves. F055 is sized to maintain upstream piping at 500 psig and 10 percent accumulation. Relief valve F055 is sized to relieve 266,500 lb/hr of fluid at the set point of 500 psig. F005, F025, and F030 are set at the design pressure specified in the process data drawing plus 10 percent accumulation. Relief valve capacity, nominal set points, set point tolerance, and ASME class ratings are provided in Table 5.4-2a.

Redundant interlocks prevent opening valves to the low pressure suction piping when the reactor pressure is above the shutdown range. These same interlocks initiate valve closure on increasing reactor pressure. The pressure interlock circuitry associated with F008 and F009 is as follows:

There are two contacts, one in the valve opening circuit, the other in the valve closing circuit. The logic is such that, if the relay is deenergized, the opening circuit is disabled and the closing circuit is made (valve will close). The logic for the relay coil is such that the relay will deenergize on (among other conditions) reactor pressure greater than a low pressure set point. The relay for valve F008 is powered from RPS Bus A, while the relay for F009 is powered from RPS Bus B. There are two sets of contacts (for high pressure) in the logic circuit of each relay which will deenergize the relay. One of the contacts is operated by a trip unit powered from RPS Bus A; the other trip unit contact is supplied from RPS Bus B. There is no diversity requirement for this application.

The pressure permissive set point to open RHR isolation valves F008 and F009 is 135 psig (nominal). The same set point initiates closure of F008 and F009 on increasing reactor pressure.

Thermal relief for the RHR piping between isolation valves F008 and F009 during a postulated LOCA or steam line break is provided by check valve F308 on the 3/4-inch relief line. Any increase in pressure in the piping between F008 and F009 beyond the pressure in the vessel suction line (essentially vessel pressure) would open the check valve sufficiently to pass the small flow necessary to relieve any thermal overpressure condition. The differential pressure necessary to crack F308 is less than 1 psid.

In addition a high pressure check valve will close to prevent reverse flow if the pressure should increase. Relief valves in the discharge piping are sized to account for leakage past the check valve.

5.4.7.1.3.1 RHR System Relief with Respect to Operator Errors

During plant startup the RHR system is not used and is there- fore isolated from the RCS. There will be no operator interface with the RHR system during startup.

RHR pressure relief capacity is not sized on a basis of operator error during shutdown, since no operator error can lead to over-pressurization of the low pressure piping. RHR low pressure piping is connected to the higher pressure RCS during normal shutdown at the shutdown suction from the recirculation loop and at the shutdown return to feedwater. The pressure separation design of these lines is discussed in the following paragraphs.

a. RHR shutdown suction from the recirculation loop:

   This line has an inboard containment isolation valve and an outboard containment isolation valve. Each valve is interlocked with a separate switch which prohibits opening of the associated valve if the reactor pressure exceeds the interlock setpoints. These same interlocks initiate valve closure on increasing reactor pressure. An operator error cannot open either valve in either line at a pressure above the piping design pressure.

b. RHR shutdown return to feedwater:

   This line has a check valve and a globe valve at the pressure boundary. The check valve is not controlled by the operator, and therefore no operator error can open the valve and pressurize the low pressure piping. The globe valve has a pressure interlock which prevents opening of the valve due to operator error when the higher pressure system exceeds the shutdown range. This same interlock initiates valve closure on increasing reactor pressure.

c. All valves performing an isolation function between the high-pressure and low-pressure boundary in the RHR system are categorized as Category A valves in accordance with the ASME OM Code for Operation and Maintenance of Nuclear Power Plants. These valves will be leak rate tested to the requirements of ASME OM Code.

5.4.7.1.4 Design Basis With Respect to General Design Criterion 5

The RHR system for this unit does not share equipment or structures with any other nuclear unit.

5.4.7.1.5 Design Basis for Reliability and Operability

The design basis for the shutdown cooling mode of the RHR system is that this mode is controlled by the operator from the control room. The only operation performed outside of the control room for a normal shutdown is manual operation of local flushing and warming valves, as described in subsection 5.4.7.2.6.

Two separate shutdown cooling loops are provided; although both loops are required for shutdown under normal circumstances, the reactor coolant can be brought to 212°F in less than 20 hours with only one loop in operation. With the exception of the shutdown suction, shutdown return and abandoned steam supply and condensate discharge lines, the entire RHR system is part of the ECCS and containment cooling systems, and is therefore required to be designed with redundancy, flooding protection, piping protection, power separation, etc., required of such systems. (See Section 6.3 for an explanation of the design bases for ECCS systems.)

Shutdown suction and discharge valves are required to be powered from both offsite and standby emergency power for purposes of isolation and shutdown following a loss of offsite power. In the event either of the two shutdown supply valves fails to operate, an operator is sent out to operate the valve manually. If this is not feasible and the plant must be shut down as soon as possible, the alternate shutdown method must be employed. In this procedure, water is drawn from the suppression pool, pumped through the RHR heat exchanger, and delivered into the shroud region of the reactor. The vessel water is allowed to overflow the steam lines and discharges back to the suppression pool via the ADS valve discharge lines. A complete loop is thereby established, with sensible and decay heat being transferred to the pool and then to the standby service water system via the RHR heat exchanger. [HISTORICAL INFORMATION] [In response to Requirement 2.1.2 of NUREG-0578, the BWR Owner's Group (TMI) has tested the safety/relief valves (S/RV) for conditions that would be experienced during alternate shutdown. The test results indicate flow capacities in excess of 8000 gpm per valve.] The pneumatic supply system associated with the ADS valves is described in subsection 5.2.2.4.1. All components that are a part of the alternate shutdown loop (ECCS pumps and valves, ADS valves, MSIVs, etc.) are routinely tested at the plant in accordance with the plant technical specifications and Technical Requirements Manual (TRM).

5.4.7.1.6 Design Basis for Protection from Physical Damage

The design basis for protection from physical damage such as internally generated missiles, pipe break, and seismic effects, are discussed in Sections 3.5, 3.6, and 3.7, respectively.

5.4.7.2 Systems Design

5.4.7.2.1 System Diagrams

All of the components of the RHR system are shown in the P&ID, Figures 5.4-16, 5.4-17 and 5.4-17a. A description of the controls and instrumentation is presented in subsection 7.3.1.1.1, Emergency Core Cooling Systems Control and Instrumentation.

A process diagram and process data are shown in Figures 5.4-18 and 5.4-19. All of the sizing modes of the system are shown in the process data.

Interlocks are provided: (1) to prevent drawing vessel water to the suppression pool; (2) to prevent opening vessel suction valves above the suction line or the discharge line design pressure; (3) to prevent inadvertent opening of containment spray valves while in shutdown; (4) to prevent opening low pressure steam supply valve F087 (valve administratively de-energized) when vessel pressure is above line design rating; and (5) to prevent pump start when suction valve(s) are not open. A tabular description of RHR system logic (i.e., interlocks, permissives) is given in Table 5.4-3.

5.4.7.2.2 Equipment and Component Description

a. System Main Pumps

The RHR main system pumps are motor-driven deepwell pumps with mechanical seals and cyclone separators. The motors are air cooled by the ventilating system. The pumps are sized on the basis of the LPCI mode (Mode A) and the minimum flow mode (Mode G) of the Process Data Figures 5.4-18 and 5.4-19. Design pressure for the pump suction structure is 220 psig with a temperature range from 40 to 360 F. Design pressure for the pump discharge structure is 500 psig. The bases for the design temperature and pressure is maximum shutdown cut-in pressures and temperature, minimum ambient temperature, and maximum shutoff head. The pump pressure vessel is carbon steel, the shaft and impellers are stainless steel.

A curve showing the required NPSH is included with the pump characteristic curves provided in Figure 5.4-20. The three-stage pumps require a minimum NPSH of 2 feet at both the design flow, 7450 gpm, and pump maximum design runout flow of 8940 gpm. The minimum NPSH requirement is, as specified by the manufacturer, to be evaluated at a point 3 feet above the top of the pump mounting flange (this reference point is 4-3/4" above the pump suction nozzle centerline).

Design calculations, based on the Regulatory Guide 1.1 position, indicate an available NPSH in each RHR loop sufficient to ensure pump performance capable of accomplishing the required safety functions. Original design basis NPSH calculations are provided in Appendix 6E. Extended power uprate operation increased reactor decay heat, which increases the heat addition to the suppression pool for all accident events and caused the suppression pool design temperature to increase. Hence, the NPSH margins for the RHR pumps were evaluated for the limiting conditions following a design basis LOCA at 102% of the EPU rated thermal power and assuming the failure of one of the two RHR heat exchangers. The limiting conditions depend on the pump flow rates, debris loading on the suction strainers, pipe frictional losses, suppression pool level, and suppression pool temperature. As described in Section 2.6.1.1.1.1 of the PUSAR, the resulting calculated peak suppression pool temperature was 189°F which is within the ECCS NPSH pump limit of 194°F for debris generating events. The highest bulk pool temperature response from a non-LOCA event is from an alternate shutdown cooling event. For this event, the peak bulk suppression pool temperature is 198°F which is also within the ECCS NPSH pump limit of 212°F for non-debris generating events.

Normal testing of the RHR pumps during operation takes suction from the suppression pool, passes through the heat exchangers (loops A and B only) and returns the water to the suppression pool through the RHR test return line.

Restricting orifice plates are located in the test return line of all three RHR loops. These orifice plates are sized to restrict test mode flow to 110 percent of that specified for the testing mode with all throttle valves wide open. The flow specified for testing is 7450 gpm which is equal to the minimum specified LPCI flow. Therefore, the orifice plates are sized to limit test flow to about 8200 gpm.

The Grand Gulf RHR pumps were performance tested for a runout flow of about 8800 gpm and therefore can accommodate the maximum test mode flow without damage.

b. Suction Strainers

Details of the RHR pumps suction strainers located inside the suppression pool are provided in subsection 6.2.2.2.

c. Heat Exchangers

The “A” and “B” loops of RHR each have two heat exchangers in series that act as a single unit (sometimes referred to as “the RHR heat exchanger.”) This unit is sized to provide the heat transfer capability required for the post accident suppression pool cooling (also called containment cooling) mode of operation. This mode of operation has the highest heat transfer requirements. The heat exchangers are also capable of meeting the requirements of all other modes discussed in 5.4.7.1.1. These other modes have different flow rates and/or inlet temperatures which change the heat transfer capability. Design heat transfer capacity for various modes of operation are listed in the table below.

Mode of Operation	Design Heat Transfer Requirements
Shutdown Cooling (maximum)	155.7×10^6 BTU/hr
Low Pressure Injection Mode	Not required
Suppression Pool Cooling	184.7×10^6 BTU/hr
Containment Spray Cooling	155.2×10^6 BTU/hr

Flow rates are 7450 gpm (rated) on the shell side and 7900 gpm (rated) on the tube side (service water side). Rated inlet temperature is 185°F shell side and 90°F tube side. The overall heat transfer coefficient is 210 Btu/hr-ft^2-F. As described in Section 5.4.7.1.1.1, the effects of EPU caused an increase in the shutdown cooling times due to the increase in suppression pool temperature from 185°F to 210°F. The exchangers contain 21,300 ft^2 of effective surface area (assuming 5% of tubes are plugged). Design temperature range of both shell and tube sides are 40°F to 480°F. Design pressure is 500 psig on both sides, fouling factors are 0.0005 shell side and 0.002 tube side. The construction materials are carbon steel for the pressure vessel with 7030 Copper Nickel tubes and Copper Nickel clad tube sheet.

d. Valves

All of the directional valves in the system are conventional gate, globe, and check valves designed for nuclear service. The injection valves, reactor coolant isolation valves, and pump minimum flow valves are high speed valves, as operation for LPCI injection or vessel isolation requires. Valve pressure ratings are, as necessary, to provide the control or isolation function; i.e., all vessel isolation valves are rated as Class 1 nuclear valves rated at the same pressure as the primary system.

Steam pressure-reducing valves (valves administratively deenergized) are designed to regulate steam flow into the heat exchangers from full reactor pressure to maintain downstream pressure at 200 psig.

e. ECCS Portions of the RHR System

The ECCS portions of the RHR system include those sections described through Mode A-1 of the Process Diagram Figures 5.4-18 and 5.4-19.

The route includes suppression pool suction strainers, suction piping, RHR pumps, discharge piping injection valves, and drywell piping into the vessel nozzles and core region of the reactor vessel.

Pool cooling components include pool suction strainers, suction piping, pumps, heat exchangers, and pool return lines.

Containment spray components are the same as pool cooling except that the spray headers replace the pool return lines.

RHR pump damage due to high runout flows during ECCS modes is prevented as follows:

1. The LPCI injection piping has a restricting orifice (D004) to prevent excessively high runout flow rates.

2. The containment spray piping has higher frictional losses and elevational requirements than the LPCI injection piping; therefore, RHR flow to containment

spray will always be less than the above LPCI injection flow rate and, as a result, an acceptable runout flow rate.

The RHR A and B pump will trip when neither of the two suction paths has the valves aligned to provide a suction source. The pump trip does not compromise the ECCS function further than loss of suction source to that loop. The RHR A and B loops have two suction sources which contain motor-operated valves: the suppression pool and the RPV recirculation loop. Pump operation interlocks to suction valve position are provided to prevent an operator error from damaging the pump. If an operator error which closes the suction path does occur, the interlock will prevent that loop from accomplishing any ECCS function since the result is no source of water; there will be no further ECCS degradation.

5.4.7.2.3 Controls and Instrumentation

Controls and instrumentation for the RHR system are described in Chapter 7.

5.4.7.2.4 Applicable codes and classifications

Piping, pumps and valves		
a. Process side 1/2	ASME III	Class
b. Service water side	ASME III	Class 3
Heat exchangers		
a. Process side (Shell Side)	ASME III TEMA Class C	Class 2
Electrical portions		
a. IEEE 279		
b. IEEE 308		
ADHRS		
Piping, pumps and valves		
a. Process side	ASME III	Class 2/3
b. Plant servise water side	ASME III	Class 3 (isolation valves and within)
	ANSI B31.1	(outside isolation valves)

Heat exchangers		
a. Process side (shell side)	ASME III TEMA Class 2	Class 3
Electrical portions		
a. Non Class-1E		

The manual actions required for the most limiting failure are discussed in subsection 5.4.7.1.5.

5.4.7.2.5 Reliability Considerations

The residual heat removal system has included the redundancy requirements of subsection 5.4.7.1.5. Two completely redundant loops have been provided to remove residual heat, each powered from a separate, emergency bus. With the exception of the common shutdown cooling line, all mechanical and electrical components are separate. Either loop is capable of cooling down the reactor within a reasonable length of time.

5.4.7.2.5.1 Pump Endurance Testing

[HISTORICAL INFORMATION] [A 200-hour endurance test was performed in two parts on two separate Byron Jackson manufactured pumps of deep draft design and similar in construction to those at Grand Gulf. A 150-hour test was performed on the TVA 18 HPCS pump to demonstrate the capability of long-term operation. A total of ten spin-downs were recorded throughout the test to determine if any binding was occurring. The test results indicate that no binding in the throttle bushing or other running clearance occurred that would affect the pump performance.

Table 5.4-2b shows the endurance test summary sheet for the TVA 18 pump test.

All the spin-down times were normal, and the post-test teardown inspection revealed no abnormal conditions of any pump parts. The dimensions of all parts remained within print tolerances. There were some minor indications on the throttle bushings, one bearing, and some of the wear rings which were probably caused by foreign material, but this was not detrimental to the pump operation.

A 50-hour test was performed on the River Bend-2 LPCS pump. Table 5.4-2c shows the endurance test summary sheet for the River Bend-2 pump.

The RHR pump for Grand Gulf is a three-stage pump with a 37-inch OD casing and a length of 281 inches below its mounting flange. The approximate length of the column plus pump stages is 320 inches. The pump has 24-inch suction and 18-inch discharge nozzles. The pump is specified and tested to deliver 7620 gpm at 301-foot total dynamic head.

The LPCS pump that was tested is a four-stage pump rate at 5125 gpm at 725-foot total dynamic head. This pump has a 20-inch suction and a 14-inch discharge nozzle. Its length below mount is 251 inches and its barrel diameter is 34 inches. The approximate length of the pump and motor is 478 inches.

The HPCS pump is a 13-stage unit rated at 7275 gpm at 965-foot total dynamic head. The HPCS pump has a length below mounting flange of 283 inches, a barrel diameter of 37 inches, and the length of the pump and motor is approximately 472 inches.

Grand Gulf ECCS pump characteristics are provided in Table 5.4-2d. Additionally, Table 5.4-2e provides a list of deep draft design pumps in operation at other plants, including the pump characteristics and estimated hours of operation.

The Grand Gulf pumps manufactured by Byron-Jackson have been custom designed, as are most of the Byron-Jackson pumps. Although there are no identical pumps in the field from which to quote use history, the pumps listed in Table 5.4-2e do exhibit similar pump characteristics and they provide a meaningful comparison. All the pumps compared are vertical, deep draft pumps with multiple stages and are located in a pressurized one-piece can or barrel as are the Grand Gulf pumps.

Some of the pumps do not use a double suction first stage (DX identifies a double suction pump).

The design similarities are shown by the designation letters of a given pump. All pumps for a given designation are from a similar family and share common characteristics and the hydraulic characteristics are geometrically similar. For example, a designation 30 CKX pump is a 20 CKX pump scaled up.

Grand Gulf has performed additional testing of an installed RHR pump (manufactured by Byron-Jackson) to demonstrate reliability under long-term operation. This test consisted of running a single RHR pump for a continuous 24-hour period during the preoperational test (E12-PT01). The test plan included provisions for taking data as follows:

1. Motor bearing temperatures
2. Pump vibrational measurements
3. Pump discharge pressure
4. Pump suction pressure

The test results from the continuous 24-hour period are provided in Table 5.4-2f.]

5.4.7.2.6 Manual Action

a. Residual Heat Removal (Shutdown Cooling Mode)

   In shutdown operation, when vessel pressure is 135 psig or less, the pool suction valve is closed for the initial shutdown loop. Then local manually-operated flushing valves are opened, and the stagnant water flushed to the suppression pool. At the end of this nominal flush, Standby Service Water flow is started and aligned to the RHR heat exchanger.Vessel suction valves are opened to allow prewarming of the lower half of the shutdown loop with effluent directed through manual valves to radwaste. The radwaste effluent valves are closed when pump warming has been accomplished. The pump is started and flow is established through the heat exchange bypass valve F048 and the return valve F053. Cooldown rate is subsequently controlled via valves F048 (heat exchanger bypass flow) and F003 (exchanger flow). All operations are performed from the control room except for opening and closing of local flush water and warming valves.

b. Deleted

5.4.7.2.7 The Effect of Single Failure

The RHR system is connected to higher pressure piping at shutdown suction, shutdown return, LPCI injection, and the RHR/RCIC steam interface. The vulnerability to overpressurization of each location is discussed in the following paragraphs.

a. Shutdown suction has two gate valves, F008 and F009, in series which have independent pressure interlocks to prevent opening at high inboard pressure for each valve. No single active failure nor operator error will result in overpressurization of the low pressure piping. In the unlikely event of leakage past F008 and F009, PT-N057 provides indication and alarm to the control room operator.

b. The shutdown return line has a swing check valve, F050, to protect it from higher vessel pressures. Additionally, a globe valve, F053, is located in series and has pressure interlock to prevent opening at high inboard pressures. No single active failure nor operator error will cause overpressurization of the lower pressure piping.

c. The LPCI injection line has an air testable swing check valve, F041, to protect it from higher vessel pressure. No single active failure nor operator error will cause overpressurization of the lower pressure piping.

d. Deleted

e. Each RHR/RCIC steam interface line is permanently isolated with two blind fittings. A relief valve, F055, is provided downstream of F051 and F087 to protect the low pressure piping. No single active failure nor operator error will cause overpressurization of the low pressure piping.

If a pipe failure should occur outside containment in the RHR system when the plant is in shutdown cooling, acceptable core cooling would be achieved by the core cooling systems. The following core cooling systems would be available to maintain core cooling:

a. If the single active failure is HPCS, the following are available: LPCS + 2LPCI

b. If the single active failure is LPCS, the following are available: HPCS + 2LPCI

c. If the single active failure is LPCI (not shutdown cooling loop), the following are available: HPCS + LPCS + 1LPCI

During operation in Mode 3 below the RHR cut in permissive pressure a reduced complement of ECCS subsystems provide the required core cooling thereby allowing alignment of one LPCI for decay heat removal.

The maximum discharge rate resulting from the largest crack in the RHR piping outside containment as determined by the NRC criteria is 1,688 gpm.

The following signals automatically isolate F008 and F009 as a result of a pipe failure outside containment:

a. RPV water level low (Level 3)

b. RPV pressure high

c. Equipment area temperature high

The failed pipe will automatically be isolated and the feedwater system will maintain water level.

If the feedwater flow were terminated before the pipe failure occurred, then the HPCS and RCIC would automatically start and maintain the vessel water if Level 2 were reached.

If the HPCS is the assumed single failure, then the RCIC alone would maintain water level. The RCIC will maintain water level only if the reactor pressure is greater than 60 psig.

Even if no credit were taken for RCIC, if the feedwater system were not operating, and if the HPCS system is assumed to have failed, F008 and F009 will isolate on Level 3 RPV water level approximately 2 minutes after the pipe failure. The operator would have approximately 25 to 30 minutes to manually initiate the low pressure ECC systems to replenish water level and maintain adequate core cooling.

The operator would be alerted to the failed pipe outside containment by:

a. Equipment area temperature high

b. RPV water level low (Level 3)

c. RHR equipment room sump level high

d. RHR equipment room radiation high

Appropriate action will be provided by applicable Alarm Response Instruction(s).

5.4.7.3 Performance Evaluation

Thermal performance of the RHR heat exchangers is based upon containment cooling with excess capability for the shutdown mode.

Because shutdown is usually a controlled operation, maximum service water temperature less 10°F is used as the service water inlet temperature. These are nominal design conditions; if the service water temperature is higher, the exchanger capabilities are reduced and the shutdown time is longer and vice versa.

5.4.7.3.1 Shutdown With All Components Available

No typical curve is included here to show vessel cooldown temperatures vs time due to the infinite variety of such curves that may be due to: (1) clean steam systems that may allow the main condenser to be used as the heat sink when nuclear steam pressure is insufficient to maintain steam air ejector performance; (2) the condition of fouling of the exchangers; (3) operator use of one or two cooling loops; (4) coolant water temperature; (5) system flushing time. Since the exchangers are designed for the fouled condition with relatively high service water temperature, the units have excess capability to cool when first cut in at high vessel temperature. Total flow and mix temperature must be controlled to avoid exceeding 100°F per hour cooldown rate. (See subsection 5.4.7.1.1.1 for minimum shutdown time to reach 212°F.)

Upon initiation of shutdown cooling, the operator will maintain a plot of the reactor cooldown rate. The plot will be compared to a 100°F per hour cooldown rateline. Temperature changes for any interval which is greater than 100°F per hour will be evident by the slope of the plotted line. The operator will then adjust the cooldown rate so that the change in temperature over any one-hour period does not exceed Technical Specification limits. Reactor cooldown rate will be plotted every 15 minutes. There will be sufficient staff present to handle this and other evolutions. Staffing will meet the minimum NRC shift manning requirements as discussed in Section 13.1.

5.4.7.3.2 Shutdown With Most Limiting Failure

Shutdown under conditions of the most limiting failure is discussed in subsection 5.4.7.1.1.1. The capability of the heat exchanger for any time period is balanced against residual heat, pump heat, and sensible heat. The excess over residual heat and pump heat is used to reduce the sensible heat.

5.4.7.4 Preoperational Testing

[HISTORICAL INFORMATION] [The preoperational test program and startup test program are used to generate data to verify the operational capabilities of each piece of equipment in the system: each instrument, each set point, each logic element, each pump, each heat exchanger, each valve, and each limit switch. In addition these programs verify the capabilities of the system to provide the flows, pressures, condensing rates, cooldown rates, and reaction times required to perform all system functions as specified for the system or component in the system data sheets and process data. Logic elements are tested electrically; valve pumps, controllers, and relief valves are tested mechanically; finally the system is tested for total system performance against the design requirements as specified above using both the offsite power and standby emergency power. Preliminary heat exchanger performance can be evaluated by operating in the pool cooling mode, but a vessel shutdown is required for the final check due to the small temperature differences available with pool cooling.]

5.4.7.5 Alternate Decay Heat Removal

An auxiliary cooling loop is included in the RHR system with separate pumps, heat exchangers, and controls. The auxiliary cooling loop is used to provide an alternate method of decay heat removal during cold shutdown and refueling conditions. Piping in the RHR A, B, and C loops is utilized for suction and discharge paths as shown in Figures 5.4-16, 5.4-17, and 5.4-17a. Cooling water is supplied by the plant service water system.

The alternate decay heat removal subsystem (ADHRS) is designed for use during operational conditions 4 and 5 to provide decay heat removal when maintenance is being performed on RHR shutdown cooling loops or associated support systems. The functional design basis for the ADHRS is to maintain reactor coolant temperatures below technical specification limits during cold shutdown and refueling operations. The functional purpose for the ADHRS is not safety-related, however, various portions are designated as safety-related to ensure that interfacing plant systems are not degraded. During operational conditions 1, 2, and 3 the ADHRS is isolated by normally closed, locked closed, or deenergized valves from interfacing plant systems.

The two pumps utilized by ADHRS are 50% capacity horizontal centrifugal pumps which when operated in parallel deliver approximately 3600 GPM. Two 50% capacity U-tube heat exchangers are used in a parallel arrangement to provide the required decay heat removal. The pumps and the heat exchangers are designed to the requirements of ASME Section III, Class 3. The pumps and heat exchangers are installed in the RHR C pump room.

Piping and components used for reactor water flow to and from the ADHRS are designed in accordance with ASME III, Class 3 or Class 2 and to Seismic Category I requirements. PSW piping inside the RHR C pump room up to the isolation valves located outside the pump room are also ASME III, Class 3 and designed to Seismic Category I requirements. Other PSW piping is ANSI B31.1 and designed for SSE loads. A non safety-related room air conditioner is installed in the RHR C pump room to maintain normal room temperatures during ADHRS operation.

Control of the ADHRS is remote manual from the main control room. Individual manual control of pump operation with pump running status lights is provided. Flow indication and temperature indication (ADHRS heat exchangers inlet and outlet temperature) is also provided in the main control room. Manual control of the ADHRS flow control valve E12F424 is provided. Local manual control of the ADHRS air conditioning unit is provided in the RHR C pump room.

Administrative controls that govern the use of ADHRS are contained in the technical specifications.

The power supply to ADHRS components is non class 1E.

The ADHRS is designed to be operated in the following modes:

a. Suppression Pool to Suppression Pool Flush/Test Mode

A suction path from the suppression pool through the E12F004C, E12F066C, and G41F057 valves can be established to test ADHRS flow capabilities or to flush the system. The suppression pool water is pumped through the ADHRS pumps, heat exchangers, flow control valve and back to the suppression pool via the RHR C full flow test return line (through valve E12F021).

b. Vessel to Vessel Cooling Mode via RHR A

Using the existing RHR shutdown cooling suction piping through E12F008 and E12F009, reactor coolant is pumped through the E12F006A and E12F066A to the ADHRS heat exchangers. The reactor coolant is cooled and returned to the reactor vessel through the ADHRS flow control valve E12F424 and the RHR C injection valve E12F042C.

c. Vessel to Vessel Cooling Mode via RHR B

Using the existing RHR shutdown cooling suction piping through E12F008 and E12F009, reactor coolant is pumped through the E12F006B and E12F066B to the ADHRS heat exchangers. The reactor coolant is cooled and returned to the reactor vessel through the ADHRS flow control valve E12F424 and the RHR C injection valve E12F042C.

d. Spent Fuel Pool to Vessel Mode

A flow path may be established from the spent fuel pool via the G41F226 and G41F348 valves to the ADHRS heat exchangers. A return path to the reactor vessel is provided through ADHRS flow control valve E12F424 and the RHR C injection valve E12F042C. Operation in this mode is limited to operational condition 5 when the upper cavity is flooded. During these times, the reactor vessel may communicate with the spent fuel pool via the fuel transfer tube.

The ADHRS is isolated during normal operation by locked closed valve E12F410 in the suction piping and normally closed check valve E12F416 in the discharge piping. The PSW cooling water supply is isolated by locked closed valves P44F483 and P44F484.

Within 30 days of placing the ADHRS into operation for the removal of decay heat, the ADHRS may be unisolated from interfacing plant systems during Modes 1, 2, and 3 under administrative controls for the purpose of valve surveillance testing and filling, venting, and flushing of the primary and PSW sides of the ADHRS. Additionally, the E12-F066A&B valves may be operated under administrative controls during Modes 1, 2, and 3 to allow MOVAT/ VOTES testing.

5.4.8 Reactor Water Cleanup System

The reactor water cleanup system is an auxiliary system, a small part of which is part of the reactor coolant pressure boundary up to and including the outermost containment isolation valve. The other portions of the system are not part of the reactor coolant pressure boundary and are isolatable from the reactor.

5.4.8.1 Design Bases

5.4.8.1.1 Safety Design Bases

The RCPB portion of the RWCU system:

a. Prevents excessive loss of reactor coolant

b. Prevents the release of radioactive material from the reactor

5.4.8.1.2 Power Generation Design Bases

The reactor water cleanup system:

a. Removes solid and dissolved impurities from reactor coolant

b. Discharges excess reactor water during startup, shutdown, and hot standby conditions

c. Minimizes temperature gradients in the recirculation piping and vessel during periods when the main recirculation pumps are unavailable

d. Conserves reactor heat

e. Enables the major portion of the RWCU system to be serviced during reactor operation

5.4.8.2 System Description

The reactor water cleanup system (see Figures 5.4-21 through 5.4-26) continuously purifies the reactor water. The system operates in two distinct modes, pre-pump mode or post-pump mode.

In the pre-pump mode reactor water is taken from the inlet side of each of the reactor recirculation pumps and from the bottom of the reactor vessel and routed through the RWCU pumps. The temperature of the water is then reduced by passing through the tubes of the regenerative heat exchangers and the nonregenerative heat exchangers. After filtration and deionization by the filter-demineralizers, the water is reheated when passed through the shell side of the regenerative heat exchangers and is returned to the reactor vessel by way of the residual heat removal and feedwater systems.

In the post-pump mode reactor water is taken from the inlet side of each of the reactor recirculation pumps and from the bottom of the reactor vessel and through the regenerative and nonregenerative heat exchangers. The much cooler water then passes through the RWCU pumps. This flow path is utilized in order to extend the life of the RWCU pump seals. After filtration and deionization by the filter-demineralizers, the water is reheated when passed through the shell side of the regenerative heat exchangers and is returned to the reactor vessel by way of the residual heat removal and feedwater systems.

The reactor water cleanup system can also be aligned to return processed water to the main condenser or to radwaste rather than the reactor vessel.

The cleanup system can be operated at any time during planned operations, or it may be shut down. The cleanup system is classified as a primary power generation system. The cleanup system is not an essential safety system.

The major equipment of the reactor water cleanup system is located in the containment. This equipment includes regenerative and non-regenerative heat exchangers and filter-demineralizers with regeneration equipment. The cleanup pumps are located in the auxiliary building. The entire system is connected by associated valves and piping; controls and instrumentation provide proper system operation. Design data for the major pieces of equipment are presented in Table 5.4-4.

The limits for reactor coolant have been established in accordance with the guidance provided in Table 1 of Regulatory Guide 1.56, Revision 1 (July 1978), and are listed in Appendix 16B along with the frequency and analysis requirements. The methods of chemical analysis of pH, conductivity, and chlorides are presented in approved plant procedures.

The conductivity meter for the RWCU shall be electronically calibrated in accordance with approved plant Maintenance Calibration Instructions (MCI). A correlation will be performed to compare the installed process conductivity monitors with an independent in-line flow cell under controlled conditions. The correlation will be performed in accordance with approved plant procedures.

Flow rates through each RWCU filter demineralizer vessel are measured by a flow orifice and flow transmitter on the discharge line of each demineralizer vessel with each flow being indicated locally on the filter-demineralizer control panel.

The quantity of principal ions likely to cause demineralizer breakthrough is not calculated for the RWCU. However, differential pressure (ΔP) and decontamination factor values are monitored, and RWCU demineralizers shall be removed from service when established limits are reached.

The temperature of the filter-demineralizer units is limited by the resin operating temperature. Therefore the reactor coolant must be cooled before being processed in the filter-demineralizer units. The regenerative heat exchanger transfers heat from the tubeside (hot process) to the shellside (cold process). The shell-side flow returns to the reactor. The non-regenerative heat exchanger cools the process further by transferring heat to the component cooling water system. The non-regenerative heat exchanger is sized to maintain the required filter-demineralizer temperature, even when the effectiveness of the regenerative heat exchanger is partially reduced by diversion of a portion of the process to either the main condenser or the radwaste system.

The filter-demineralizer units (see Figures 5.4-25 and 5.4-26) are pressure precoat type filters using resin media. Spent resins are not regenerable and are sluiced from the filter-demineralizer unit to a backwash receiving tank from which they are transferred to the radwaste system for processing and disposal. To prevent resins from entering the reactor recirculation system in the event of failure of a filter-demineralizer resin support, a strainer is installed on the outlet of each filter-demineralizer unit. Each strainer has a control room alarm that is energized by high differential pressure. A bypass line is provided around the filter-demineralizer units for bypassing the units.

Monitoring of resin media transfer from the precoat tank onto the elements of the filter-demineralizer is done through observation of the clarity of water in the precoat tank. Precoat recirculation is to continue until the precoat tank water is clear. Monitoring of the backwash process which transfers the spent resinous materials and accumulated insolubles from the filter-demineralizer to the backwash receiving tank is not necessary. The system is designed to make this transfer by pressure difference between the filter-demineralizer and the backwash receiving tank and after buildup of air pressure in the filter-demineralizer and by gravity flow.

Valves in slurry service (precoat and backwash lines) are globe or plug type and are designed to prevent the accumulation of particles that may interfere with the operation of the valves. The piping has been designed so that there are no air traps, loop seals, dead legs, etc., in the piping in order to prevent accumulation of the resins.

In the event of low flow or loss of flow in the system, flow is maintained through each filter-demineralizer by its own holding pump. Sample points are provided in the common influent header and in each effluent line of the filter-demineralizer units for continuous indication and recording of system conductivity. High conductivity is annunciated in the control room. The alarm set points of the conductivity meters at the inlet and outlet of the RWCU demineralizers are 1.0 mho/cm and 0.1 mho/cm, respectively. The influent sample point is also used as one of the normal sources of reactor coolant grab samples. Sample analysis also indicates the effectiveness of the filter-demineralizer units.

The suction line of the RCPB portion of the RWCU system contains five motor-operated isolation valves which automatically close in response to signals from the RCPB leak detection system and actuation of the standby liquid control system. (Sections 7.6 and 5.2 describe the system, and it is summarized in Table 5.2-9). This action prevents the loss of reactor coolant and release of radioactive material from the reactor. It also prevents removal of liquid poison by the cleanup system should the SLCS be in operation.

The outboard isolation valve will automatically close to prevent damage of the filter-demineralizer resins if the outlet temperature of the nonregenerative heat exchanger is high. The RCPB isolation valves may be remote manually operated to isolate the system equipment for maintenance or servicing.

A remote manual-operated gate valve on the return line to the reactor provides long term leakage control. Instantaneous reverse flow isolation is provided by check valves in the RWCU piping.

Operation of the reactor water cleanup system is controlled from the control room. Resin-changing operations, which include backwashing and precoating, are controlled from a local control panel in the auxiliary building. The time required to remove a unit from the line, backwash and precoat is normally less than one hour.

5.4.8.3 System Evaluation

The RCPB isolation valves and piping are designed to the requirements defined in Section 3.2, Classification of Structures, Components, and Systems, and the requirements of the containment and reactor vessel isolation control system, in subsection 7.3.1.1.2.

5.4.9 Main Steam Lines and Feedwater Piping

5.4.9.1 Safety Design Bases

a. The main steam, feedwater, and associated drain lines are protected from potential damage due to fluid jets, missiles, reaction forces, pressures, and temperatures resulting from pipe breaks.

b. The main steam, feedwater, and drain lines are designed to accommodate stresses from internal pressures and earthquake loads, without a failure that could lead to the release of radioactivity in excess of the guide-line values in published regulations.

c. The main steam and feedwater lines are designed with suitable accesses to permit in-service testing and inspections.

d. The main steam lines are analyzed for dynamic loadings due to fast closure of the turbine stop valves.

e. The main steam piping from the reactor up to and including the main steam shutoff valve, the feedwater piping from the reactor up to and including the feedwater inlet shutoff valve, and smaller connecting lines are seismic Category I.

f. The main steam and feedwater piping and smaller connected lines are designed in accordance with the requirements of Table 3.2-1, Item II.

5.4.9.2 Power Generation Design Bases

In order to satisfy the design bases:

a. The main steam lines have been designed to conduct steam from the reactor vessel over the full range of reactor power operation.

b. The feedwater lines have been designed to conduct water to the reactor vessel over the full range of reactor power operation.

5.4.9.3 Description

The main steam piping is described in Section 10.3, Main and Reheat Steam System. The main steam piping from the reactor up to and including the shutoff valve and the feedwater piping is depicted in Figure 5.2-6. The main steam isolation valves are discussed in subsection 5.4.5. The design pressure and temperature of the main steam lines and isolation valves are listed in Table 5.2-3.

The feedwater piping consists of two 24 inch outside diameter lines from the high pressure feedwater heaters which each split into three 12 inch risers after the inlet isolation valve to the reactor. Each line includes isolation valves as discussed in subsection 6.2.4.3.1.1.1. The design pressure and temperature of the feedwater piping between the reactor and the second isolation valve from the reactor are listed in Table 5.2-3.

The general requirements of the feedwater control system are described in subsections 7.7.1.4, 7.7.2.4, and 10.4.7.

The main steam and feedwater piping components extending from the outboard isolation valves through the turbine building wall (see Figure 5.2-6), are classified as ASME Section III, Class 2, and meet all of the materials and fabrication requirements of Subsection NC and the applicable material specifications. Impact testing has not been specified for the Class 2 piping and components.

The permissible lowest service metal temperature is a function of the metal thickness and the service conditions of the fluid in that component. The lowest service metal temperature is governed by the requirements of the ASME Code. The lowest service temperature as defined in the Code is the minimum temperature of the fluid retained by the component whenever the pressure within the component exceeds twenty percent of the pre-operational system hydrostatic test. The actual lowest service temperature which could be experienced by the containment boundary materials, meets the requirements for the lowest service metal temperature for the governing conditions. The feedwater check valve discs were changed to stainless steel to meet this requirement. Procedures are in place to ensure that train B of the feedwater system will not experience service temperatures of less than +65 F.

Low alloy steels are not used in the Class 2 portions of the main steam and feedwater systems. All materials used for pressure-retaining parts are listed in Appendix I to ASME Sections III. Materials used for the Class 2 portions of the main steam system are as follows:

a. Pipe - SA 106 Gr. C

b. Valves - SA 216 Gr. WCB

c. Forgings - SA-105

Materials used for the Class 2 portion of the feedwater system are as follows:

a. Pipe - SA 106 Gr. B or SA 106 Gr. C

b. Valves - SA 105

c. Forgings - SA-105

Regulatory Guide positions are discussed in Appendix 3A.

5.4.9.4 Safety Evaluation

Differential pressure on reactor internals under the assumed accident condition of a ruptured steam line is limited by the use of flow restrictors and by the use of four main steam lines. Subsection 5.4.4 describes the details of the flow restrictors. All main steam and feedwater piping is designed in accordance with the requirements defined in Section 3.2, Classification of Structures, Components and Systems. Design of the piping in accordance with these requirements ensures meeting the safety design bases.

5.4.9.5 Inspection and Testing

Inspection and testing is performed in accordance with applicable codes. In-service inspection is considered in the design of the main steam and feedwater piping. This consideration assures adequate working space and access for the inspection of selected components.

5.4.10 Pressurizer

Not Applicable to BWRs

5.4.11 Pressurizer Relief Valve Discharge System

Not Applicable to BWRs

5.4.12 Valves

5.4.12.1 Safety Design Bases

a. Line valves in the residual heat removal, reactor core isolation cooling, reactor water cleanup, high pressure core spray, low pressure core spray, and standby liquid control systems and located beyond the reactor coolant pressure boundary are designed to operate efficiently and to maintain the integrity of the individual fluid system's boundary.

b. The valves are designed to operate under the internal pressure and temperature loading as well as the external loading experienced during the various systems transient operating conditions.

c. The valves are designed in accordance with the applicable requirements of Table 3.2-1. Compliance with ASME Codes is discussed in subsection 5.2.1.

d. The design loading, design procedure, and acceptability criteria are described in subsection 3.9.3.

5.4.12.2 Description

Line valves such as gate, globe, and check valves are located in the fluid systems to perform a mechanical function.

Line valves furnished are manufactured standard types, designed and constructed in accordance with the requirements of ASME

Code, Section III for Classes 1, 2, and 3 valves. All materials, exclusive of seals and packing, are designed for a 40-year plant life under the environmental conditions applicable to the particular system when appropriate maintenance is periodically performed.

Power operators are sized to operate successfully under the maximum differential pressure determined in the design specification.

5.4.12.3 Safety Evaluation

Line valves are shop tested by the manufacturer for performability. Pressure retaining parts are subject to the testing and examination requirements of Section III of the ASME Code. To minimize internal and external leakage past seating surfaces, maximum allowable leakage rates are stated in the applicable design specifications. The maximum allowable main seat and back seat leakage is 2 cc/hr/in. of seat diameter and .25 cc/hr/in. of seat diameter, respectively, for globe valves. The allowable seat leakage for check valves is 10 cc/hr/in. of seat diameter.

Power actuators are subjected to a shop functional test to ensure that the actuators and accessories perform as required. Valve construction materials are compatible with the maximum anticipated radiation dosage for the service life of the valves.

5.4.12.4 Inspection and Testing

Valves serving as containment isolation valves and which must remain closed or open during normal plant operation are partially exercised during this period to assure their operability at the time of an emergency or faulted condition. Other valves, serving as system block or throttling valves, are exercised without jeopardizing system integrity for the same reason.

Leakage from valve stems on valves located in the drywell is monitored by use of doublepacked stuffing boxes with an intermediate lantern leakoff connection for detection and measurement of leakage rates.

[HISTORICAL INFORMATION] [Motors used with valve actuators have been furnished in accordance with applicable industry standards. Each motor actuator has been assembled, factory tested and adjusted on the valve for proper operation, position and torque switch setting, position transmitter function (where applicable) and speed requirements. Valves have additionally been tested to demonstrate adequate stem thrust (or torque) capability to open (or close) the valve within the specified time at specified differential pressure. Tests verified no mechanical damage to valve components during full stroking of the valve. Suppliers were required to furnish assurance of acceptability of the equipment for the intended service based on any combination of:

a. Test stand data

b. Prior field performance

c. Prototype testing

d. Engineering analysis

Preoperational and operational testing performed on the installed valves consists of total circuit check out and performance tests to verify speed requirements at specified differential pressure.]

5.4.13 Safety and Relief Valves

5.4.13.1 Safety Design Bases

a. Overpressure protection is provided at isolatable portions of the residual heat removal, reactor core isolation cooling, reactor water cleanup, high pressure core spray, low pressure core spray, and standby liquid control systems in accordance with the rules set forth in the ASME Code, Section III, for Classes 1, 2 and 3 components. Subsection 5.2.2 discusses Class 1 safety/relief valves.

b. The design pressures and temperatures and code classifications for the valves are listed in Table 5.2-3. The valves are designed in accordance with the requirements listed in Table 3.2-1.

c. The design loading, design procedure, and acceptability criteria are described in subsection 3.9.3.

d. The design and installation details for the mounting of pressure relief devices are described in subsection 3.9.3.3.

5.4.13.2 Description

Safety or pressure relief valves are designed and constructed in accordance with the same code class as that of the line valves in the system.

5.4.13.3 Safety Evaluation

The use of pressure relieving devices assures that overpressure does not exceed 10 percent above the design pressure of the system. The number of relieving devices on a system or portion of a system is determined on an individual component basis. In accordance with ASME Code requirements, all safety valves are constructed so that failure of any part cannot obstruct the free discharge of steam or water from the valve.

5.4.13.4 Inspection and Testing

The valves are inspected and tested in accordance with the requirements of ASME Section XI. In addition shop performance tests are performed on the valves to ensure their operability in accordance with design specification requirements.

No provisions are to be made for in-line testing of spring-loaded safety/relief valves. Certified set pressures and relieving capacities are stamped on the body of the valves by the manufacturer and further examinations would necessitate removal of the component.

5.4.14 Component Supports

5.4.14.1 Safety Design Bases

a. Component supports in the residual heat removal, reactor core isolation cooling, reactor water cleanup, high pressure core spray, low pressure core spray, and standby liquid control systems beyond the reactor coolant pressure boundary, but closely allied with the reactor coolant system, are designed in accordance with subsection 3.9.1. Reactor vessel supports are discussed in subsection 5.3.3.1.4.1.

b. Flexibility and seismic analysis for Classes 1, 2, and 3 components conforms with the appropriate requirements of ASME Code, Section III. Support types, materials used for fabricated support elements, and recommended pipe support spacing conform to ASME Code, Section III, subsection NF, and the revision of Code Case 1644 listed in Table 5.2-1.

5.4.14.2 Description

The use and location of rigid-type supports, variable or constant spring-type supports, snubbers, and anchors or guides are determined by flexibility and seismic and stress analysis. Component standard supports are utilized to the maximum extent possible. Direct weldments to pipe wall are analyzed.

5.4.14.3 Safety Evaluation

Design loadings used for flexibility and seismic analysis toward the determination of adequate component support systems include all transient loading conditions expected by each component. Provisions are made for spring-type supports for the initial dead weight loading due to hydrostatic testing of steam systems to prevent damage to this type support. Component supports are further discussed in subsection 3.9.3.4.

5.4.14.4 Inspection and Testing

[HISTORICAL INFORMATION] [After completion of the installation of a support system, all hanger elements are visually examined to assure that they are in correct adjustment in their cold setting position. Upon hot startup operations, thermal growth is observed to confirm that spring-type hangers, snubbers, and constant supports function properly between their hot and cold setting positions. Final adjustment capability is provided on spring supports, snubbers, constant supports, rod hangers, and sway struts. Weld inspection and standards are in accordance with ASME Code, Section III. Welder qualifications and welding procedures are in accordance with ASME Code, Section IX.]

5.4.15 References

1. Ianni, P.W., "Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors," APED-5458, March 1968.

2. "Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves," APED-5750, General Electric Co., Atomic Power Equipment Department, March 1969.

3. Letter, A.B. Wang, NRC to Vice President Operations, Entergy Operations, Inc., Grand Gulf Nuclear Station, "Grand Gulf Nuclear Station Unit 1 - Issuance of Amendment RE: Extended Power Uprate (TAC No. ME4679)," July 18, 2012.

4. GGNS-NE-10-00075, Rev. 1, GGNS EPU T0400 Containment System Response, January 2012.

TABLE 5.4-1: REACTOR RECIRCULATION SYSTEM DESIGN CHARACTERISTICS

External Loops	
Number of Loops	2
Pipelines Sizes (nominal O.D.)	
Pump suction, in.	24
Pump discharge, in.	24
Ring header nominal size, in.	16
External riser nominal size, in.	12
Internal riser nominal size, in.	10
Design Pressure (psig)/Design Temperature, (F)	
Suction piping and valve up to and including pump suction nozzle	1250/575
Pump, discharge valves, and piping between	1650/575
Piping after discharge blocking valve up to vessel	1550/575
Vessel bottom drain	1250/575
Pump cooling water piping	150/330
Pump seal leakoff piping	100/300
Operation at Rated Conditions	
Recirculation Pump	
Flow, gpm	44,600*
Flow, lb/hr	$16.86 \times 10^{6*}$
Total developed head at Rated Flow, ft	765*
Pump suction static pressure, psia	1043
Available NPSH at Rated Flow	111
Water Temperature at Inlet, F	533
Pump brake HP at Rated Flow, hp	7490*
Suction Velocity at Rated Flow, ft/sec	39.2*

TABLE 5.4-1: REACTOR RECIRCULATION SYSTEM DESIGN CHARACTERISTICS (Continued)

Pump Motor

Voltage rating	6600
Speed, RPM	1780
Motor rating, HP	8099
Phase	3
Frequency	60 Hz
Rotational Inertia, lbs-ft	18700

Operation at Low Speed Conditions

Percent speed (pump driven by LMFG set-600V-15hz)	25%
Low speed rated flow, gpm	10,704
Head at rated flow, ft	44
Maximum pump brake horsepower - hot	149
Maximum pump brake horsepower - cold	198
Available NPSH (minimum), ft	51

Jet Pumps

Number	24
Driving Flow per Jet Pumps, lb/hr	1.42×10^{6}
Throat I.D., in.	6.4
Diffuser I.D., in.	14.7
Nozzle I.D. at Tip, in.	1.24
Diffuser exit velocity, fps	23.4
M-ratio (suction flow/drive flow)	2.319
Universal efficiency, percent	42.58
Total developed head, feet	85.51

TABLE 5.4-1: REACTOR RECIRCULATION SYSTEM DESIGN CHARACTERISTICS (Continued)

Flow Control Valve

Type	Ball
Material	Austenitic S/S
Type Actuation	Hydraulic
Failure mode (on loss of power or control signal)	As is*
Valve wide open CV (Nominal), gpm/psi	8310
Valve size diameter, in.	24

Recirculation Suction and Discharge Isolation Valves

Type	Gate Valve
Actuator	Motor
Material	Austenitic S/S
Valve size diameter, in.	24

* A minor amount of drift may occur depending upon internal hydraulic leakage and friction.

Single Loop Piping Descriptions	Quantity	Approximate Length (feet)	Nominal Size (inches)
Pump Suction Line			
Straight	-	35	24
Elbows	3	-	24
Gate valves	1	-	24
Discharge Line			
Straight pipe	-	35	24
Elbows	2	-	24
Flow control valves	1	-	24
Gate valves	1	-	24

TABLE 5.4-1: REACTOR RECIRCULATION SYSTEM DESIGN CHARACTERISTICS (Continued)

Discharge Manifold

Pipe	-	40	16
Reducer cross	2	-	24x16
Contour nozzle	6	-	12
Caps	2	-	16

No. of External Risers

Straight Pipe	-	7	12
Elbows	1	-	12

* These parameters experience negligible changes as a result of the increased drive flow necessary for the 1.7% power uprate. The following table reports the uprate values:

Flow, gpm	44,740
Flow, lb/hr	$16.91x10^{6}$
Total developed head at Rated Flow, ft	764
Pump brake HP at Rated Flow, HP	7500
Suction Velocity at Rated Flow, ft/sec	39.3

TABLE 5.4-2: RECIRCULATION SYSTEM TRIP AND START FUNCTIONS

`

	ACTION				
EVENT	A	B	C	D	E
1	X		X		X
2	X		X	X	
3		X		X	
4		X			
5				X	
6	X			X	
7	X			X	
8	X		X		X
9	X			X	
10	X		X		X

Events

1. Suction or discharge block valve less than 90% open.
2. Vessel high pressure (ATWS)
3. Turbine trip or generator load rejection.
4. 100% speed power supply trip of one of two operating recirculation pumps.
5. 100% speed power supply trip of all operating recirculation pumps.
6. Total feedwater flow less than approximately 30% nuclear boiler rated for 15 seconds.
7. Temperature difference between the main steam temperature and the recirculation pump suction temperature is less than the minimum permissable value.
8. Pump motor or LFMG set electrical protection logic is activated.
9. Vessel low level (Level 3).
10. Vessel low-low level (Level 2, ATWS)

Actions

A. Normal control trip of 100% speed power supply.

B. RPT engineered Safety Class 3 trip of 100% speed power supply.

TABLE 5.4-2: RECIRCULATION SYSTEM TRIP AND START FUNCTIONS (Continued)

C. Trip of 25% speed power supply.

D. Automatic start of LFMG set during coastdown following a 100% speed trip.

E. No automatic start of LFMG set during coastdown following a 100% speed trip.

TABLE 5.4-2a: RHR RELIEF VALVE DATA

Valve	Capacity Required/Rated (gpm)	Set Pressure[1] Max/Max +10% (psig)	ASME Class
F005	10/13.9	200/220	Section III, Class 2
F017 A, B, C	10/12.5	166/182.6	Section III, Class 2
F025 A, B, C	10/21.9	500/550	Section III, Class 2
F055 A, B	266,500/311,997 (lb/hr)	500/550	Section III, Class 2
F423A, B	10/16.3	250/275	Section III, Class 3

[1]The set point tolerance is ±2 psig for set pressures of 70 psig and below, and plus or minus 3% for set pressures over 70 psig.

TABLE 5.4-2b: [HISTORICAL INFORMATION] ENDURANCE TEST HOUR SUMMARY 150-HOUR ENDURANCE TEST - TEST DATE 21 FEB THRU 28 FEB 1979 UNIT 751-S-1324 TVA 18 HPCS MOTOR S/N CPJ 322002 (MANUFACTURER - BYRON JACKSON)

Hours	Temp.(F)	Suction Pressure (psig)	Flow (gpm)	Date
6	140-179	4.8-9.5	650	21-Feb-79
16	173-176	8.3-9.3	1775	21-22-Feb-79
5.7	190-194	3.7-6.0	6240-6260	22-Feb-79
2	124-181	4.7-13.5	5125-5175	23-Feb-79
2	190-191	11.7-11.8	4270-4320	23-Feb-79
2	175-181	8.6-9.5	2770-2800	23-Feb-79
90	175-199	8.4-12.0	605-700	23-27-Feb-79
16	181-195	3.6-5.2	6900-6925	27-28-Feb-79
10.3	180-190	6.1-7.8	6220-6250	28-Feb-79
5 sec.	181	8.7	0	24-Feb-79

TABLE 5.4-2c: [HISTORICAL INFORMATION] ENDURANCE TEST HOUR SUMMARY 50-HOUR ENDURANCE TEST - TEST DATE 23 JAN THRU 25 JAN 1979, UNIT 741-S-1427 RIVER BEND-II LPCS MOTOR S/N FMJ 623027 (MANUFACTURER - BYRON JACKSON)

Hours	Temp.(F)	Suction Pressure (psig)	Flow (gpm)	Date
6	103-174	1.3-3.6	750	23-Jan-79
2	168-171	-4.9--5.2*	4770	23-Jan-79
2	162-163	-2.0--2.7*	4050	23-Jan-79
2	160-177	1.1-1.7	2900	24-Jan-79
7.5	180-187	2.0-2.7	1630	24-Jan-79
8	181-185	6.4-6.5	6255	24-25-Jan-79
8	183-185	10.3-10.4	5135	25-Jan-79
14	186-195	2.2-2.9	750	25-Jan-79
0.5	187	2.1	1630	25-Jan-79
5 sec.	190	2.5	0	25-Jan-79

*Pressure inches of mercury gauge

TABLE 5.4-2d: [HISTORICAL INFORMATION] GRAND GULF ECCS PUMPS(MANUFACTURER - BYRON JACKSON)

Pump	No. of Pumps	Diameter 1st Stage Case (in.)	Diameter Other Stages Case (in.)	No. of Stages	Flow (gpm)	Head (ft)	Temp. (F)	Hp	Speed (rpm)
Grand Gulf 1 RHR 30DX-20CKXH	3	30	20	3	7620	301	360	850	1780
Grand Gulf 1 LPCS 33DX-21CKX	1	33	21	4	7275	765	212	2000	1775
Grand Gulf 1 HPCS 30DX-20CKXH	1	30	20	13	1800	2875	212	3500	1780

TABLE 5.4-2e: [HISTORICAL INFORMATION] PUMP CHARACTERISTICS AND LONG-TERM OPERABILITY

Pump		No. of Pumps	Diameter 1st Stage Case (in.)	Diameter Other Stages Case (in.)	No. of Stages	Flow (gpm)	Head (ft)	Temp. (F)	Hp	Speed (rpm)	Estimated Operating-History: Hours Each Pump
Oconee 24CKXLH	1	2	24	24	10	5200	1235	290	2000	1200	41,580
	2	2	24	24	10	5200	1235	290	2000	1200	35,993
	3	2	24	24	10	5200	1235	290	2000	1200	35,281
Fort Calhoun 24CKXH		3	24	24	10	5600	1150	110	2000	1200	42,769
Indian Point 20CKXHL	2	2	20	20	14	4150	720	387	1000	1170	30,477
Indian Point 20CKXHL	3	2	20	20	14	4150	720	387	1000	1170	22,993
Arkansas 28CKXH	1	3	28	28	8	8663	1166	94	3000	1190	31,214
St. Lucie 28CKXFH	1	2	28	28	8	10200	1220	117	4000	1190	28,265
Rancho Seco 1 32CKXHL		3	32	32	8	9200	1010	140	3500	890	29,128

TABLE 5.4-2e: [HISTORICAL INFORMATION] PUMP CHARACTERISTICS AND LONG-TERM OPERABILITY (Continued)

Pump	No. of Pumps	Diameter 1st Stage Case (in.)	Diameter Other Stages Case (in.)	No. of Stages	Flow (gpm)	Head (ft)	Temp. (F)	Hp	Speed (rpm)	Estimated Operating-History: Hours Each Pump
Haynes Station 3RL16CKXL	6	3	16	4	1800	340	92	200	1800	44,000
Tradinghouse Creek 18CKX20KXL	2	18	20	2	4650	300	120	450	1750	28,000
Big Stone 26DX18KXH	3	26	18	4	3100	540	118	700	1780	16,000
Jim Bridger 26DX18KXH	9	26	18	5	3600	600	125	700	1780	16,000
Millstone 18CKXH	2	18	18	7	4300	1000	336	1250	1780	20,000
Nebraska City 26DX18KXH	3	26	18	7	3700	1040	101	1250	1800	16,000
P.H. Robinson 18CKXFL	3	18	18	8	2900	1000	108	1000	1780	20,000

TABLE 5.4-2e: [HISTORICAL INFORMATION] PUMP CHARACTERISTICS AND LONG-TERM OPERABILITY (Continued)

Pump	No. of Pumps	Diameter 1st Stage Case (in.)	Diameter Other Stages Case (in.)	No. of Stages	Flow (gpm)	Head (ft)	Temp. (F)	Hp	Speed (rpm)	Estimated Operating-History: Hours Each Pump
La Cygne 26DX18KXH	2	26	18	8	4046	1150	101	1500	1775	8,000
Council Bluffs 26DX18KXH	3	26	18	8	4300	1150	125	1500	1790	4,000

TABLE 5.4-2f: [HISTORICAL INFORMATION]
24-HOUR TEST RUN RHR PUMP B TEST DATA

	Temperature			Pressure	
Time	**Upper Bearing(C)**	**Lower Bearing (C)**	**Stator Winding (C)**	**Suction (psig)**	**Discharge (psig)**
00 min	41.8	42.6	60.6	3.5	130
15 min	47.0	44.0	76.9	-	-
30 min	50.6	45.4	87.9	-	-
45 min	53.7	46.9	94.7	-	-
60 min	54.9	47.6	96.8	3.5	130
75 min	56.2	48.1	98.8	-	-
90 min	57.2	48.5	99.9	-	-
115 min	57.9	48.8	100.6	-	-
120 min	58.6	49.2	101.1	3.5	130
3 hrs	60.1	49.5	102.4	3.5	130
4 hrs	60.7	49.8	102.4	3.5	130
5 hrs	61.1	49.9	102.4	3.5	130
6 hrs	61.1	50.0	102.9	3.5	130
24 hrs	61.1	50.1	102.6	3.5	130

VIBRATION DATA
(All Readings in Mils)

	Location				
	Motor Axis			Coupling Axis	
Time	**X**	**Y**	**Z**	**X**	**Z**
0	1.6	.11	1.4	.24	.23
2	1.6	.12	1.4	.24	.24
24	1.6	.11	1.3	.23	.21

TABLE 5.4-3: RHR PUMP/ VALVE LOGIC

Valve Number	Valve Function	Normal Position	Automatic Logic or Permissives[1]
F003A/B	Heat exchanger shell discharge	Open	None
F004A/B	Suppression pool suction	Open	Cannot be opened if F006 from same loop is open
F006A/B	Shut down to A/B loop pmps	Closed	Cannot be opened if F004 or F024 are open in same loop
F008	Outboard shutdown valve	Closed	A, B, C, D, F
F009	Shutdown valve inboard	Closed	A, B, C, D, F
F0011A/B	Condensate discharge to pool	Closed	E
F021	'C' loop discharge to pool	Closed	E

TABLE 5.4-3: RHR PUMP/ VALVE LOGIC (Continued)

Valve Number	Valve Function	Normal Position	Automatic Logic or Permissives[(1)]
F023	RPV head spray valve	Closed	A, B, C, D, F, K
F024A/B	A/B loop discharge to pool	Closed	E, I, cannot be opened if F004 from same loop is closed, automatically closes when F004 from same loop is closed
F026A/B	Condensate discharge to RCIC	Closed	E
F027A/B	A/B loop containment is01	Open	G, I cannot be opened unless F028, 42 are closed (normal operation)
F028A/B	A/B loop	Closed	H, cannot be opened unless F027 is closed (normal
F037A/B	A/B loop return to upper pool	Closed	B, F, J
F040	Flush to radwaste	Closed	D, F, J

TABLE 5.4-3: RHR PUMP/ VALVE LOGIC (Continued)

Valve Number	Valve Function	Normal Position	Automatic Logic or Permissives[1]
F042A/B/C	LPCI Injection valve	Closed	G, I
F047A/B	Heat exchanger shell inlet	Open	None
F048A/B	Heat exchanger shell bypass	Open	G, I
F049	Flush to radwaste	Closed	D, F, J
F051A/B	Steam regulating valve	Closed	Piping permanently isolated with valves administratively deenergized
F052A/B	Steam supply isolation	Closed	Piping permanently isolated with valves administratively deenergized
F053A/B	Shutdown return to feedwater	Closed	A, B, C, B, F
F060A/B	Water sampling valve	Closed	D, F, J

TABLE 5.4-3: RHR PUMP/ VALVE LOGIC (Continued)

Valve Number	Valve Function	Normal Position	Automatic Logic or Permissives[1]
F064A/B/C	RHR pump min. flow control	Open	Auto open or closed on main line low or high flow
F066A/B	Spent fuel pool/ ADHRS suction	Closed	None
F068A/B	Service water discharge	Closed	H
F073A/B	Non-Condensible vent from Hx	Closed	E
F074A/B	Non-Condensible vent from Hx	Closed	E
F075A/B	Water sampling valve	Closed	D, F, J
F087A/B	Low Pressure steam supply	Closed	Piping permanently isolated with valves administratively deenergized

TABLE 5.4-3: RHR PUMP/ VALVE LOGIC (Continued)

Valve Number	Valve Function	Normal Position	Automatic Logic or Permissives[(1)]
F082A/B	Jockey pump suction	Open	Cannot be opened if F006 from same loop is open. Will auto close if F006 from same loop opened.
F094	Service water to RHR crosstie	Closed	None
F095	Service water crosstie vent	Open	Closes when F094 or F096 are signaled open
F096	Service water to RHR crosstie	Closed	None
F290 A/B	Jockey pump discharge block valve	Open	Auto open when jockey pump starts if Feedwater Leakage Control (FWLC not actuated. Auto close if jockey pump off or if FWLC is actuated.
F004C	Supression pool suction loop C	Open	None
RHR pump A/B/C	N/A	Stopped	G, not permissive when no suction source is open
ADHRS pump A/B	N/A	Stopped	Manual start/stop, pump trip on low suction pressure

(1) See notes, sheet 4.

(1) Notes for Table 5.4-3

A. Signaled closed when RPV pressure increases to set point

B. Interlocked closed when RPV pressure is above set point

C. Permitted to open when RPV pressure is below set point

D. Signaled closed when RPV water level decreases to level 3

E. Signaled closed on LOCA signal

F. Signaled closed on leak detection signal

G. Signaled open/start on LOCA signal

H. Signaled open on combination of high drywell pressure, high containment pressure, and LOCA timer runout

I. Signaled closed on combination of high drywell pressure, high containment pressure, and LOCA timer runout (F048 only, both F003 and F047 in the same loop are open)

J. Signaled closed when Drywell Pressure is above setpoint.

K. Head spray flow path disconnected per ER 2000-0083.

TABLE 5.4-4: REACTOR WATER CLEANUP SYSTEM EQUIPMENT DESIGN DATA

System Flow Rate (lb/hr)	178,000

MAIN CLEANUP RECIRCULATION PUMPS

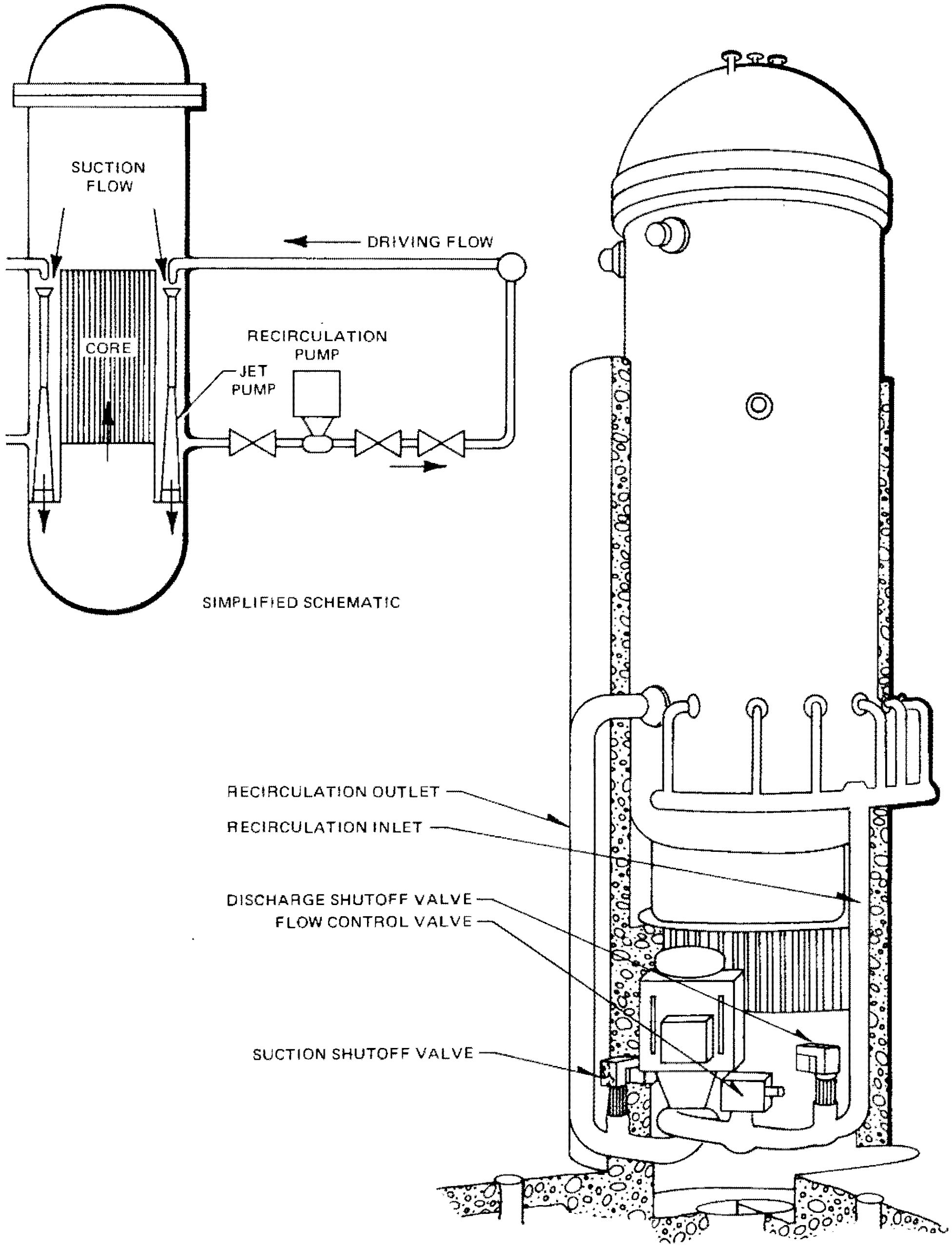
Number Required -	2
Capacity -% (each)	50
Design Temperature - (F)	575
Design Pressure - (psig)	1420
Discharge Head at Shutoff - (ft)	600
Minimum Available NPSH - (ft)	13

HEAT EXCHANGERS

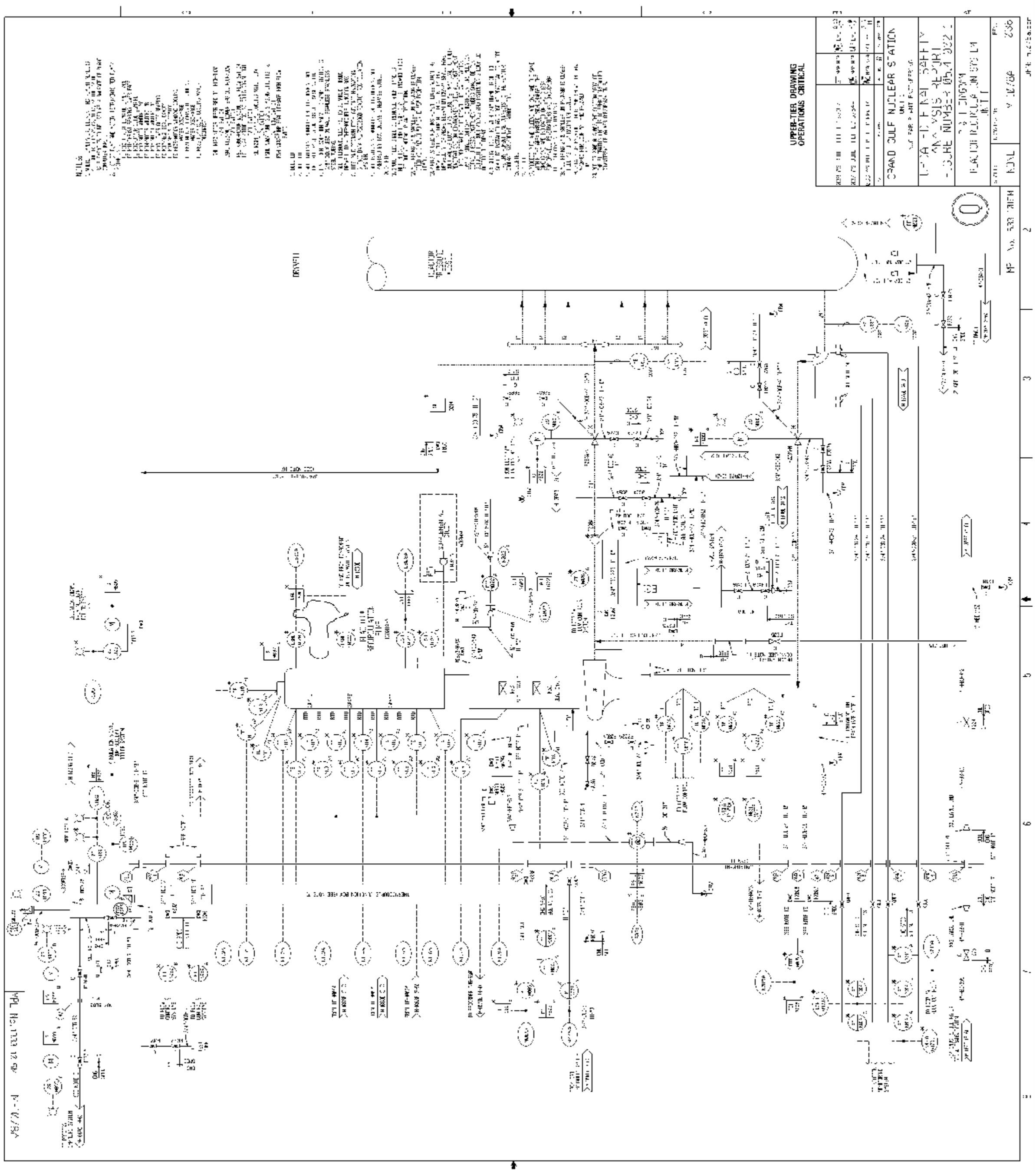
	Regenerative	Non-Regenerative
Capacity - (%)	100	100
Shell Design Pressure - (psig)	1420	150
Shell Design Temperature - (F)	575	370
Tube Design Pressure - (psig)	1420	1420
Tube Design Temperature - (F)	575	575

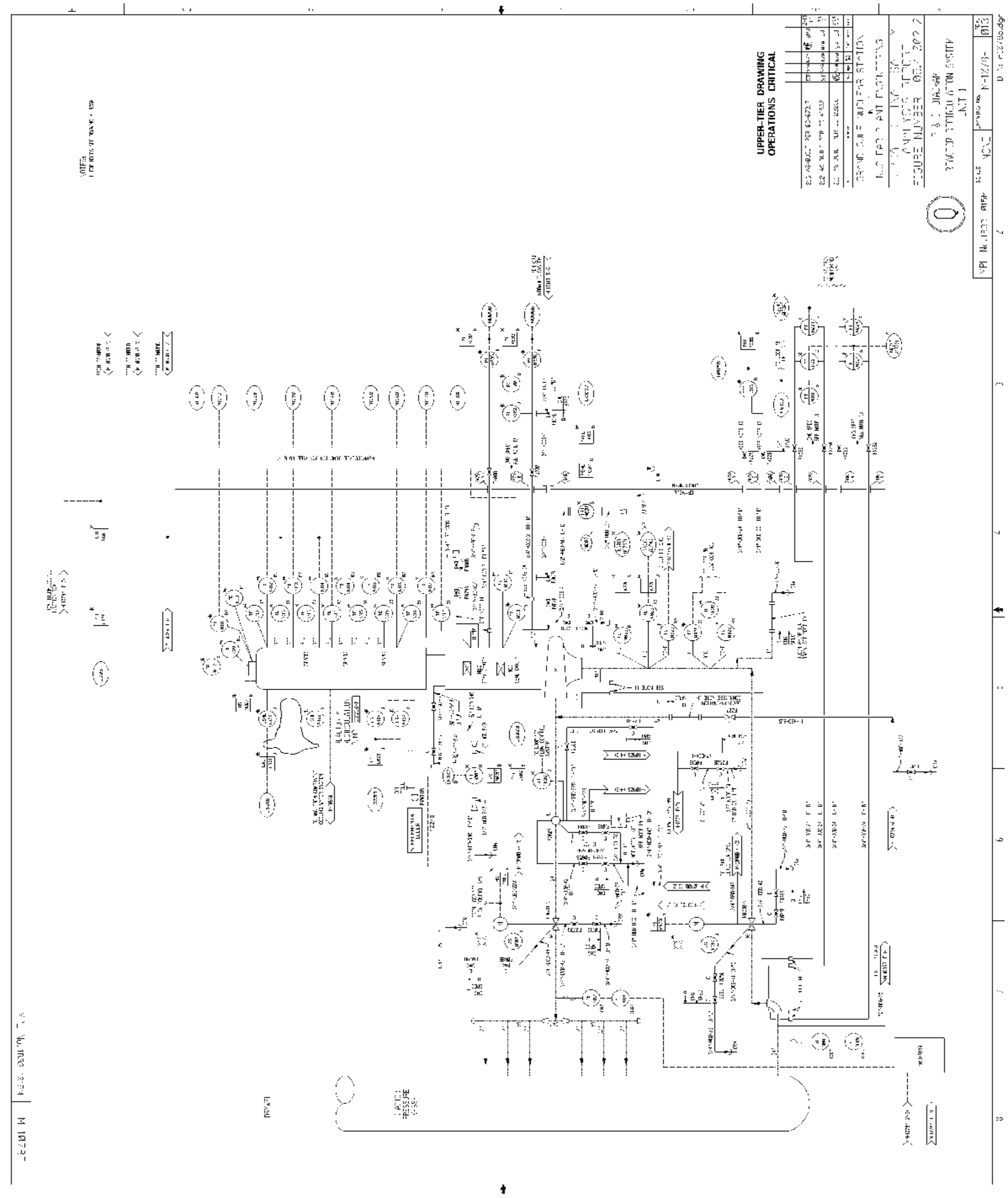
FILTER-DEMINERALIZERS

Type:	Pressure Precoat Number
Required -	2
Capacity - % (each)	50
Flow Rate Per Unit - (lb/hr)	89,000
Design Temperature - (F)	575
Design Pressure -(psig)	1420

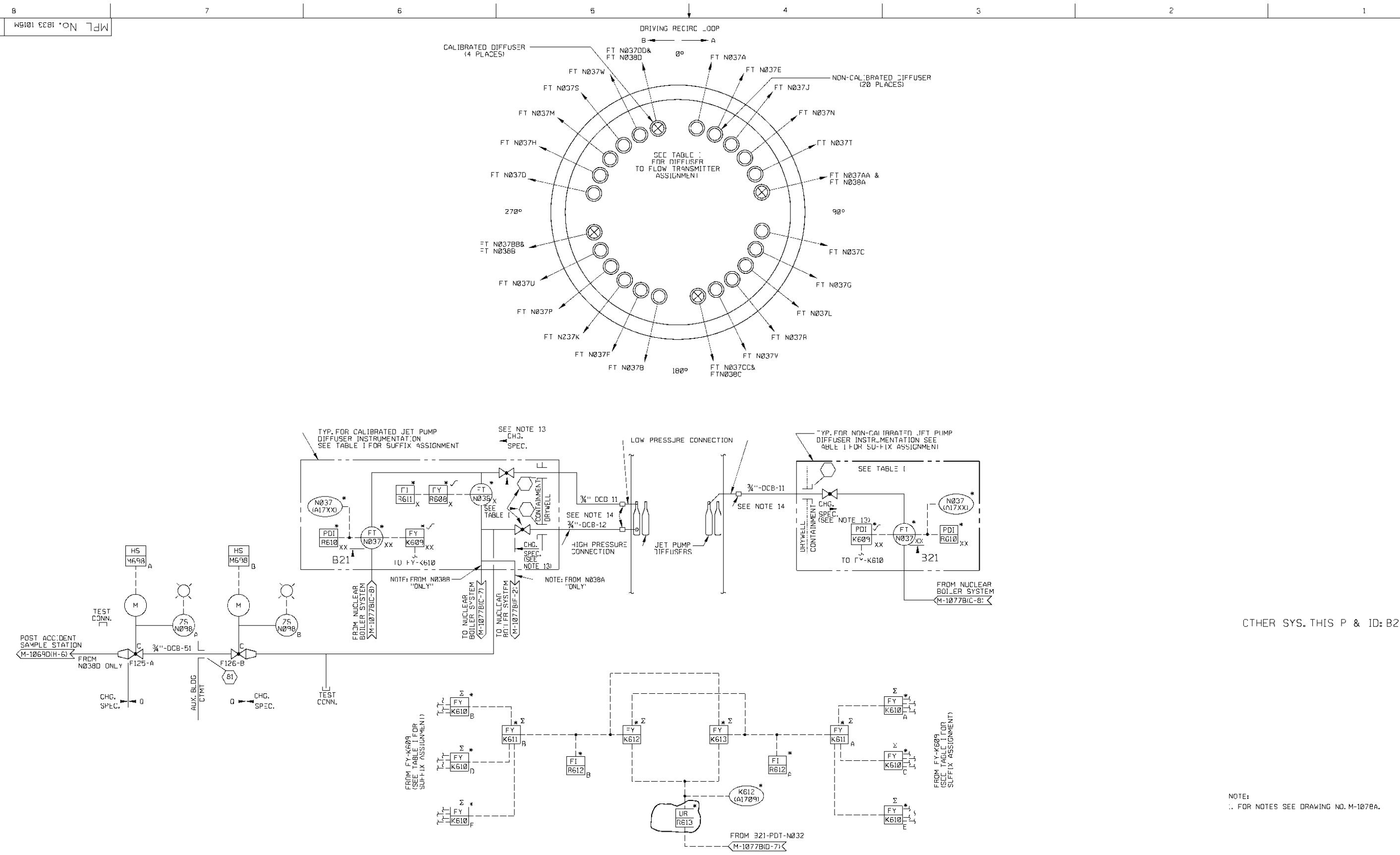


MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	RECIRCULATION SYSTEM ELEVATION AND ISOMETRIC FIGURE 5.4-1


UPPER-TIER DRAWING OPERATIONS CRITICAL
GRAND GULF NUCLEAR STATION


UPPER-TIER DRAWING
OPERATIONS CRITICAL

MPL No. 1B33 1015M M-1078B



NOTE:
1. FOR NOTES SEE DRAWING NO. M-1078A.

TABLE I JET PUMP DIFFUSER INSTRUMENTATION SUFFIX LETTER ASSIGNMENT

DIFFUSER		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
FT NØ37		A	E	J	N	T	AA	C	G	L	R	V	CC	B	F	K	P	U	BB	D	H	M	S	W	DD
PDI R61Ø		A	E	J	N	T	AA	C	G	L	R	V	CC	B	F	K	P	U	BB	D	H	M	S	W	DD
FY K6Ø9		A	E	J	N	T	AA	C	G	L	R	V	CC	B	F	K	P	U	BB	D	H	M	S	W	DD
FY K61Ø		A				C				E				B				D				F			
COMPUTER INPUT NO.		NØ37A (A1751)	NØ37E (A1752)	NØ37J (A1753)	NØ37N (A1754)	NØ37T (A1755)	N37AA (A1756)	NØ37C (A1757)	NØ37G (A1758)	NØ37L (A1759)	NØ37R (A1760)	NØ37V (A1761)	N37CC (A1762)	NØ37B (A1763)	NØ37F (A1764)	NØ37K (A1765)	NØ37P (A1766)	NØ37U (A1767)	N37BB (A1768)	NØ37D (A1769)	NØ37H (A1770)	NØ37M (A1771)	NØ37S (A1772)	NØ37W (A1773)	N37DD (A1774)
FT NØ38		—	—	—	—	—	A	—	—	—	—	—	C	—	—	—	—	—	B	—	—	—	—	—	D
FY K6Ø8		—	—	—	—	—	A	—	—	—	—	—	C	—	—	—	—	—	B	—	—	—	—	—	D
FI R611		—	—	—	—	—	A	—	—	—	—	—	C	—	—	—	—	—	B	—	—	—	—	—	D
PENETRATION NO. (L.P. CONN.)		416D	415D	415F	415A	416C	415B	415C	417C	417A	417B	417F	417D	420B	420C	420A	420F	420E	419F	420D	421F	421D	421E	421C	421A
L.P. ROOT VALVES FOR FT NØ37		FXØ5Ø	FXØ51	FXØ52	FXØ53	FXØ54	FXØ81	FXØ56	FXØ57	FXØ58	FXØ59	FXØ6Ø	FXØ79	FXØ62	FXØ63	FXØ64	FXØ65	FXØ66	FXØ8Ø	FXØ68	FXØ69	FXØ7Ø	FXØ71	FXØ72	FXØ78
PENETRATION NO. (HP CONN. FOR FT NØ38) ONLY		—	—	—	—	—	415E	—	—	—	—	—	417E	—	—	—	—	—	419E	—	—	—	—	—	421B
ROOT VALVE FOR FT NØ38	HP CONN.	—	—	—	—	—	FXØ74	—	—	—	—	—	FXØ75	—	—	—	—	—	FXØ76	—	—	—	—	—	FXØ77
	L.P. CONN.	—	—	—	—	—	FXØ81	—	—	—	—	—	FXØ79	—	—	—	—	—	FXØ8Ø	—	—	—	—	—	FXØ78
PENETRATION NO HP CLEAN FOR FT NØ37		448B												434E											

UPPER-TIER DRAWING
OPERATIONS CRITICAL

No.	REVISIONS	DWN	REV	RES ENG	CHKD	APPR	DATE
Ø14	AS-BUILT PER EC-77222	STP	N/A	N/A	EMJ	LJ	2-15-19
Ø13	AS-BUILT PER SWO: ADDED UFSAR FIGURE NO.	WE	N/A	N/A		SP	3/30/00
Ø12	AS-BUILT PER DRN 6182		N/A	N/A		WE	11-18-98

GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING

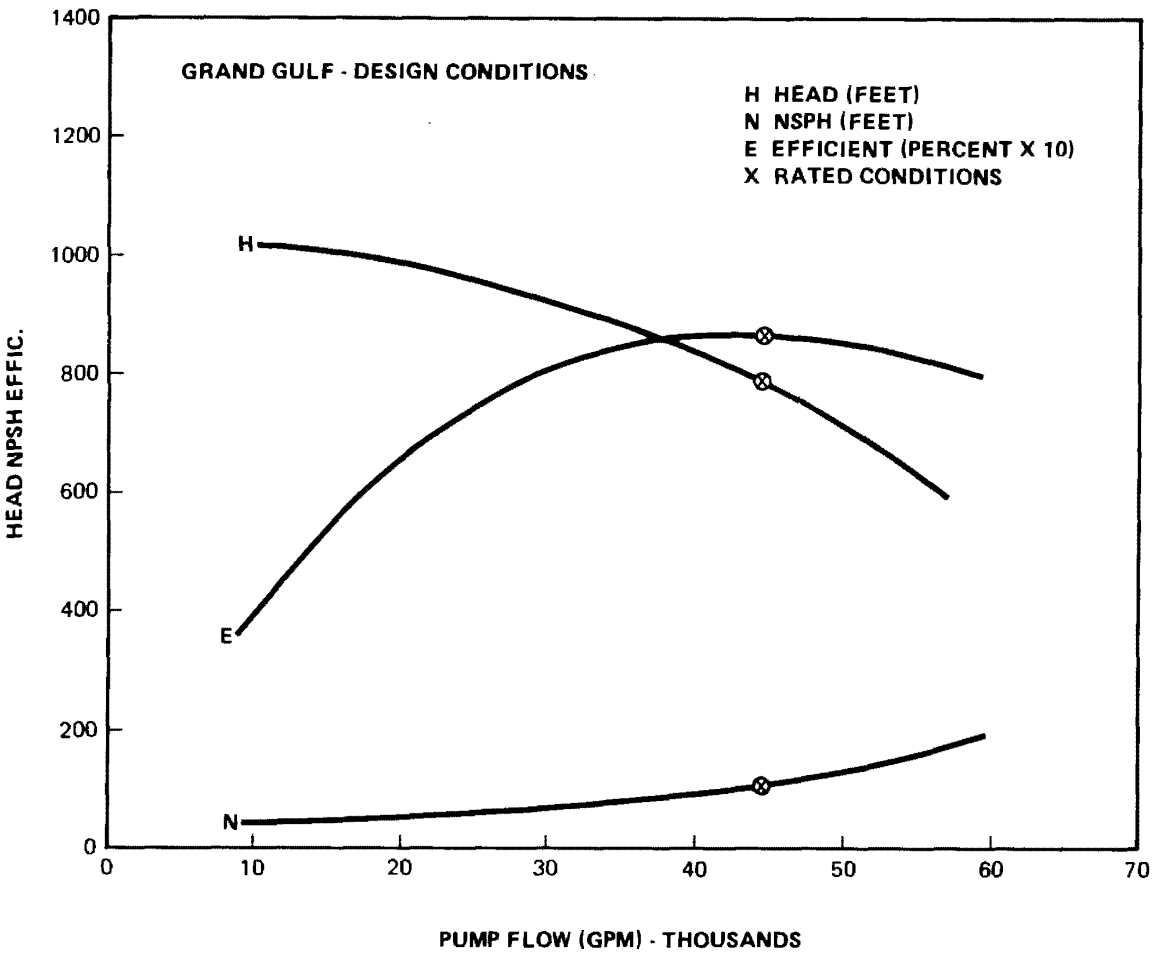
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER – 05.4–003

P & I DIAGRAM
REACTOR RECIRCULATION SYSTEM

VPL No. 1B331015M

SCALE: NONE | DRAWING No. M-1078B | REV. Ø14

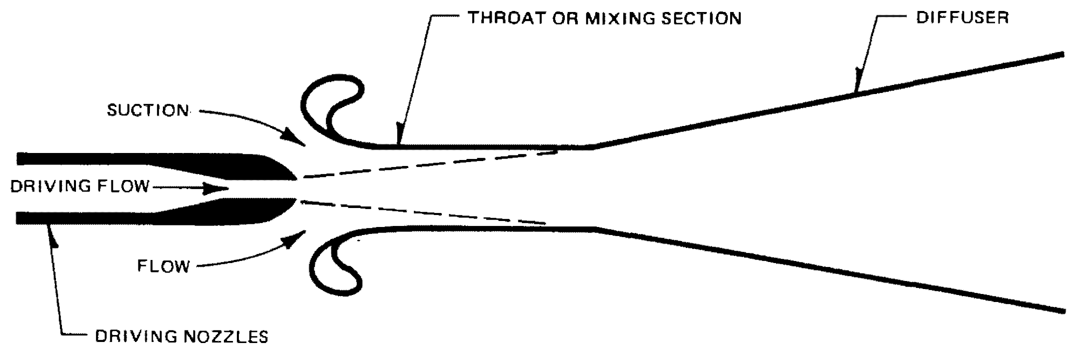
DFN: m1078b.dgn

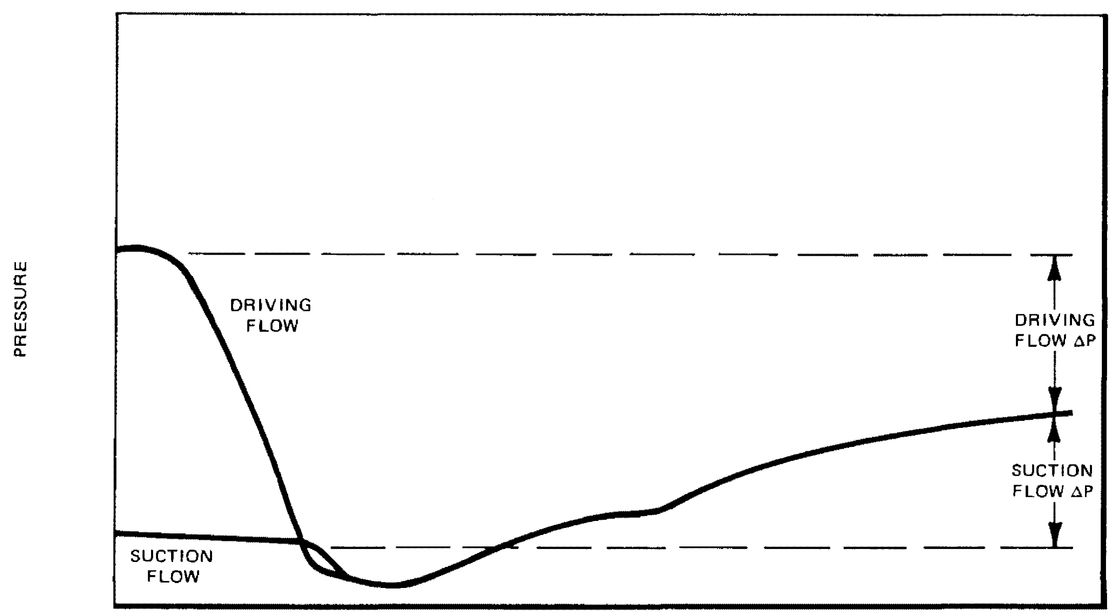


MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	AVERAGE ACTUAL RECIRCULATION SYSTEM FIGURE 5.4-4

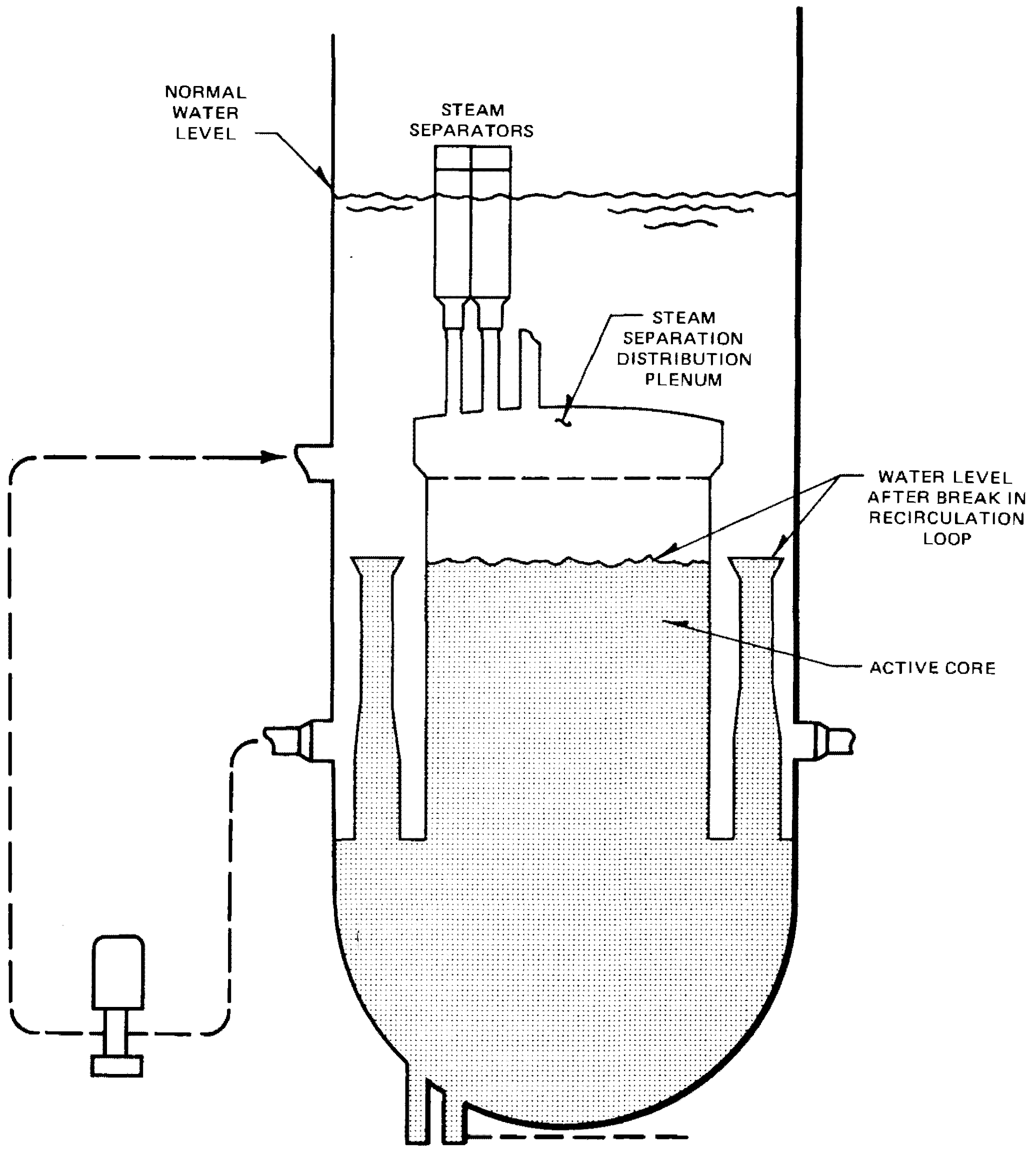
Figure 5.4-5

Deleted

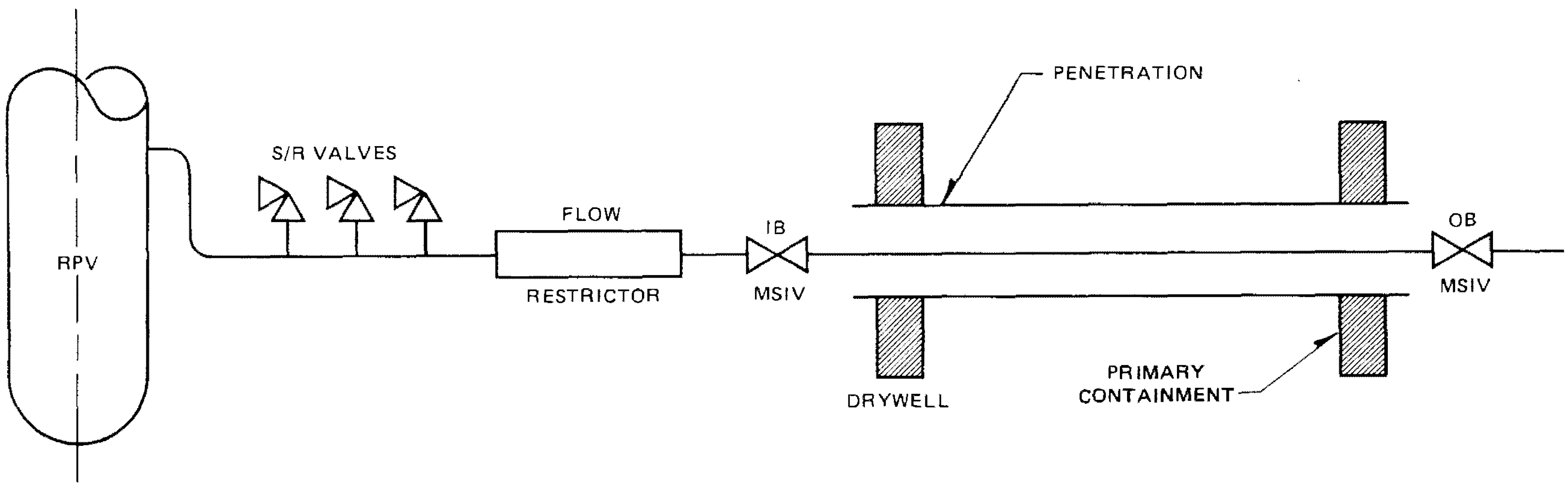




MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	OPERATING PRINCIPLE OF JET PUMP FIGURE 5.4-6



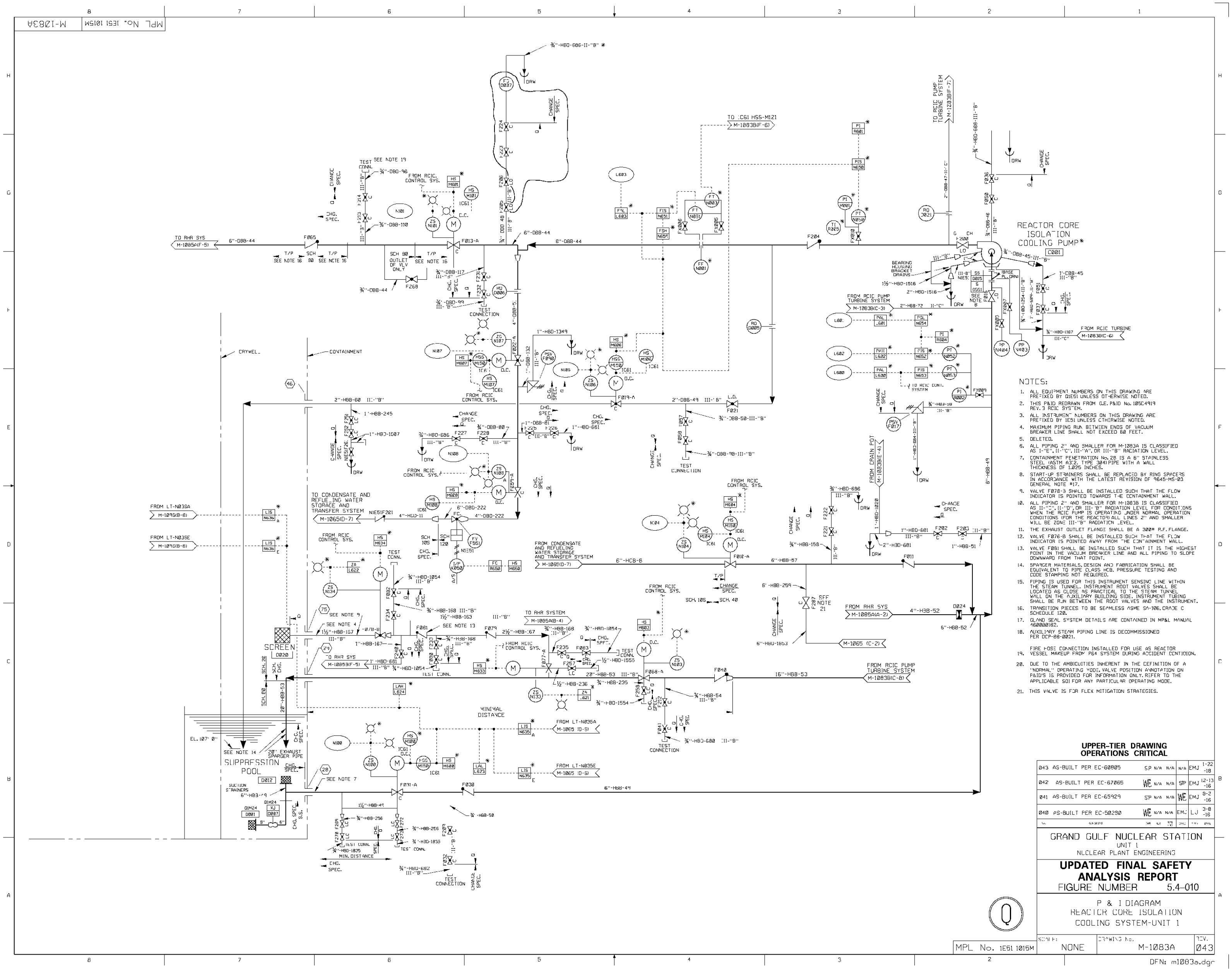
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	CORE FLOODING CAPABILITY OF RECIRCULATION SYSTEM FIGURE 5.4-7

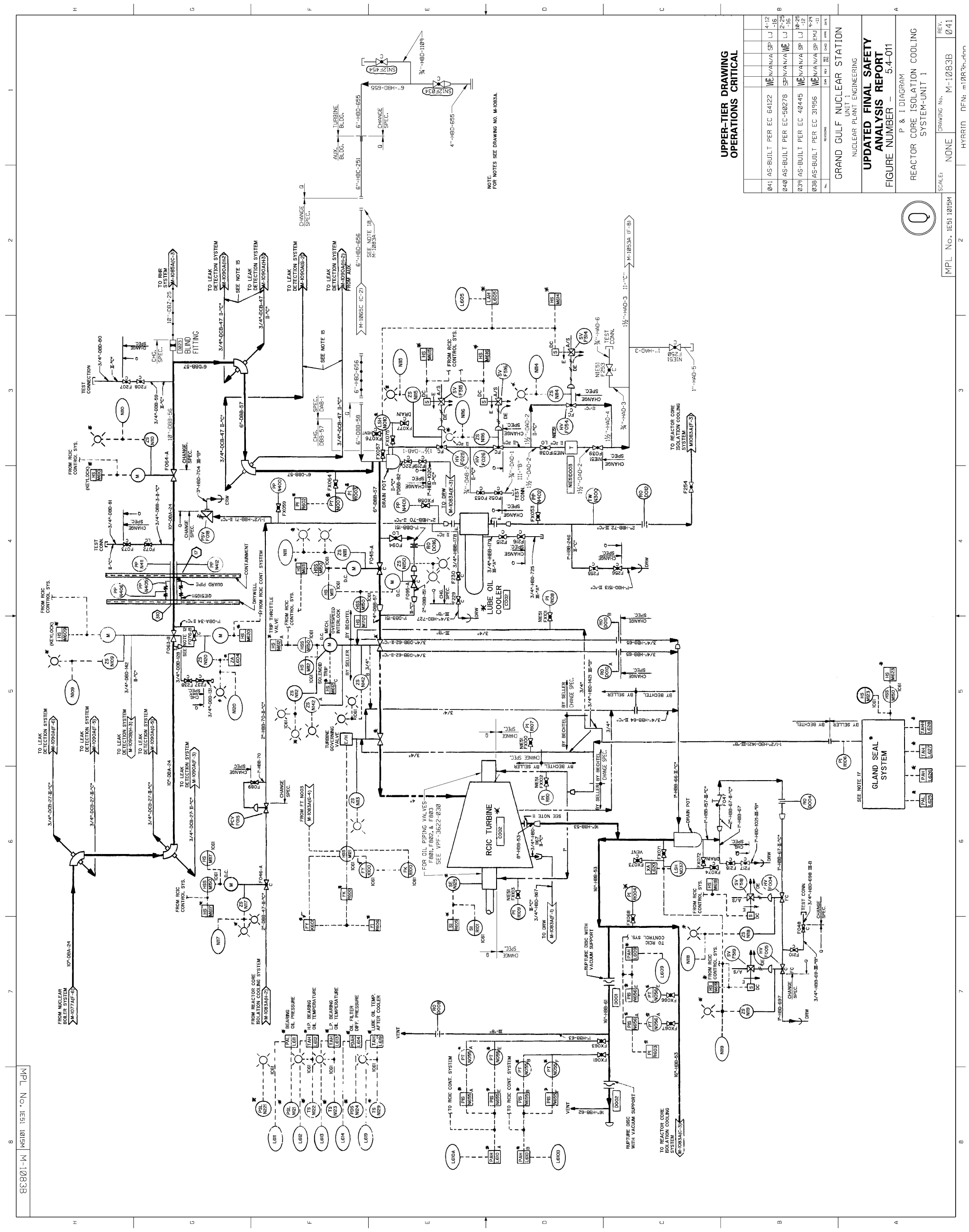


MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	MAIN STEAM LINE FLOW RESTRICTOR LOCATION FIGURE 5.4-8

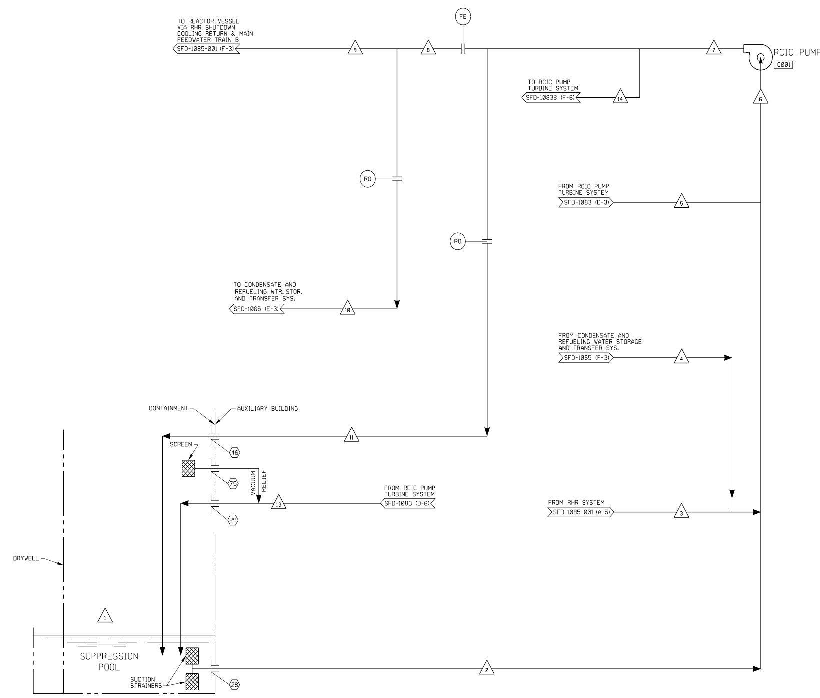
Figure 5.4-9

Deleted


MPL No. 1E51 1015M M-1083A
REACTOR CORE ISOLATION COOLING PUMP
C001
SUPPRESSION POOL
SCREEN
D020
DRYWELL
CONTAINMENT
TO RHR SYS
M-1085A(F-5)
FROM RCIC TURBINE
M-1083B(C-6)
FROM RCIC PUMP TURBINE SYSTEM
M-1083B(C-8)
FROM RHR SYS
M-1085A(A-2)
TO CONDENSATE AND REFUELING WATER STORAGE AND TRANSFER SYSTEM
M-1065(D-7)
FROM CONDENSATE AND REFUELING WATER STORAGE AND TRANSFER SYSTEM
NOTES:
1. ALL EQUIPMENT NUMBERS ON THIS DRAWING ARE PREFIXED BY Q1E51 UNLESS OTHERWISE NOTED.
2. THIS P&ID REDRAWN FROM G.E. P&ID No. 105C4919 REV. 3 RCIC SYSTEM.
3. ALL INSTRUMENT NUMBERS ON THIS DRAWING ARE PREFIXED BY 1E51 UNLESS OTHERWISE NOTED.
4. MAXIMUM PIPING RUN BETWEEN ENDS OF VACUUM BREAKER LINE SHALL NOT EXCEED 60 FEET.
5. DELETED.
6. ALL PIPING 2" AND SMALLER FOR M-1083A IS CLASSIFIED AS I-"E", II-"C", III-"A", OR III-"B" RADIATION LEVEL.
7. CONTAINMENT PENETRATION No. 28 IS A 6" STAINLESS STEEL (ASTM A312, TYPE 304) PIPE WITH A WALL THICKNESS OF 1.025 INCHES.
8. START-UP STRAINERS SHALL BE REPLACED BY RING SPACERS IN ACCORDANCE WITH THE LATEST REVISION OF 9645-MS-03 GENERAL NOTE #17.
9. VALVE F078-B SHALL BE INSTALLED SUCH THAT THE FLOW INDICATOR IS POINTED TOWARDS THE CONTAINMENT WALL.
10. ALL PIPING 2" AND SMALLER FOR M-1083B IS CLASSIFIED AS II-"C", II-"D", OR III-"B" RADIATION LEVEL FOR CONDITIONS WHEN THE RCIC PUMP IS OPERATING UNDER NORMAL OPERATION CONDITIONS (FOR THE REACTOR) ALL LINES 2" AND SMALLER WILL BE ZONE III-"B" RADIATION LEVEL.
11. THE EXHAUST OUTLET FLANGE SHALL BE A 300# R.F. FLANGE.
12. VALVE F076-B SHALL BE INSTALLED SUCH THAT THE FLOW INDICATOR IS POINTED AWAY FROM THE CONTAINMENT WALL.
13. VALVE F081 SHALL BE INSTALLED SUCH THAT IT IS THE HIGHEST POINT IN THE VACUUM BREAKER LINE AND ALL PIPING TO SLOPE DOWNWARD FROM THAT POINT.
14. SPARGER MATERIALS, DESIGN AND FABRICATION SHALL BE EQUIVALENT TO PIPE CLASS HCB. PRESSURE TESTING AND CODE STAMPING NOT REQUIRED.
15. PIPING IS USED FOR THIS INSTRUMENT SENSING LINE WITHIN THE STEAM TUNNEL. INSTRUMENT ROOT VALVES SHALL BE LOCATED AS CLOSE AS PRACTICAL TO THE STEAM TUNNEL WALL ON THE AUXILIARY BUILDING SIDE. INSTRUMENT TUBING SHALL BE RUN BETWEEN THE ROOT VALVES AND THE INSTRUMENT.
16. TRANSITION PIECES TO BE SEAMLESS ASME SA-106, GRADE C SCHEDULE 120.
17. GLAND SEAL SYSTEM DETAILS ARE CONTAINED IN MP&L MANUAL 460000182.
18. AUXILIARY STEAM PIPING LINE IS DECOMMISSIONED PER DCP-88-0021.
19. FIRE HOSE CONNECTION INSTALLED FOR USE AS REACTOR VESSEL MAKEUP FROM P64 SYSTEM DURING ACCIDENT CONDITION.
20. DUE TO THE AMBIGUITIES INHERENT IN THE DEFINITION OF A "NORMAL" OPERATING MODE, VALVE POSITION ANNOTATION ON P&ID'S IS PROVIDED FOR INFORMATION ONLY. REFER TO THE APPLICABLE SOI FOR ANY PARTICULAR OPERATING MODE.
21. THIS VALVE IS FOR FLEX MITIGATION STRATEGIES.
UPPER-TIER DRAWING
OPERATIONS CRITICAL
043 AS-BUILT PER EC-60805 SP N/A N/A N/A EMJ 1-22-18
042 AS-BUILT PER EC-67065 WE N/A N/A SP EMJ 12-13-16
041 AS-BUILT PER EC-65929 SP N/A N/A WE EMJ 8-2-16
040 AS-BUILT PER EC-50280 WE N/A N/A EMJ LJ 3-8-16
GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY
ANALYSIS REPORT
FIGURE NUMBER 5.4-010
P & I DIAGRAM
REACTOR CORE ISOLATION
COOLING SYSTEM-UNIT 1
MPL No. 1E51 1015M
SCALE: NONE
DRAWING No. M-1083A
REV. 043
DFN: m1083a.dgn


UPPER-TIER DRAWING
OPERATIONS CRITICAL
GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY
ANALYSIS REPORT
FIGURE NUMBER – 5.4-011
P & I DIAGRAM
REACTOR CORE ISOLATION COOLING
SYSTEM-UNIT 1
M-1083B
RCIC TURBINE
LUBE OIL COOLER
GLAND SEAL SYSTEM

MPL No. 1E51 1025M SFD-1083A



NOTES:

1. WATER FLOWS ARE IN GPM, FOR POINT 13 THE UNITS ARE 1,000 LBS. OF STEAM/HOUR.
2. X/Y X INDICATES MAXIMUM VALVE, Y INDICATES MINIMUM VALVE.
3. THE DATA SHOWN ON THIS FLOW DIAGRAM ARE FOR DESIGN PURPOSES ONLY, AND WHILE USEFUL AS GUIDES IN OPERATION, DO NOT REPRESENT EXACT OR GUARANTEED OPERATING CONDITIONS.
4. ALL EQUIPMENT NUMBERS ON THIS DRAWING ARE PREFIXED BY Q1E51, UNLESS OTHERWISE NOTED.
5. PUMP MINIMUM FLOW REQUIREMENTS (POINT 11) MAY OCCUR DURING ANY OPERATING MODE FLOW REQUIREMENT IS 90 GPM MINIMUM.

POINTS

	MODES	PARAMETER	1	2	3	4	5	6	7	8	9	10	11		13	14
A	SUCTION FROM CNDS. STG., REAC. & SUPPRESSION POOL AT HIGH PRESSURE (REACTOR PRESSURE = 1192 PSIA)	FLOW (SEE NOTE 1)	—	—	—	800	16	816	816	800	800	—	—		38.85	16
		TEMPERATURE (F)	140/40	—	—	100/40	100/40	100/40	100/40	100/40	100/40	—	100/40		235/60	100/40
		PRESSURE (PSIA)	18	—	—	23	65	23	1234	1223	1207	—	18		23	1234
B	SUCT. FROM CNDS. STG., REAC. AT LOW PRESS., SUPPRESSION POOL AT HIGH PRESSURE (REACTOR PRESSURE=165 PSIA)	FLOW (SEE NOTE 1)	—	—	—	800	16	816	816	800	800	—	—		12.5	16
		TEMPERATURE (F)	140/40	—	—	100/40	100/40	100/40	100/40	100/40	100/40	—	100/40		235/60	100/40
		PRESSURE (PSIA)	18	—	—	23	65	23	207	196	180	—	18		23	207
C	SUCT. FROM SUPPRESSION POOL REAC. AT HIGH PRESS., SUPPR. POOL AT LOW PRESSURE (REACTOR PRESSURE = 1192 PSIA)	FLOW (SEE NOTE1)	—	800	—	—	16	816	816	800	800	—	—		37.75	16
		TEMPERATURE (F)	140/40	140/40	—	—	140/40	140/40	140/40	140/40	140/40	—	140/40		235/60	140/40
		PRESSURE (PSIA)	14.7	16.69	—	—	65	19	1234	1223	1206	—	14.7		23	1234
D	SUCT. FROM SUPPRESSION POOL REAC. & SUPPRESSION POOL AT LOW PRESSURE. (REACTOR PRESSURE = 165 PSIA)	FLOW (SEE NOTE 1)		800	—	—	16	816	816	800	800	—	—		12.30	16
		TEMPERTURE (F)	140/40	140/40	—	—	140/40	140/40	140/40	140/40	140/40	—	140/40		235/60	140/40
		PRESSURE (PSIA)	14.7	16.69	—	—	65	19	207	196	180	—	14.7		23	207
E-1	SUCT. FROM RHR. HEAT EXCH. REAC. AT HIGH PRESS., SUPPR. POOL AT LOW PRESSURE. (REACTOR PRESSURE = 1015 PSIA)	FLOW (SEE NOTE 1)	—	—		—	16	430	430	414	414	—	—		28	16
		TEMPERATURE (F)	140/40	—		—	140/40	140/40	40/40	140/40	140/40	—	140/40		235/60	140/40
		PRESSURE (PSIA)	14.7	—		—	65	60	1050	1043	1030	—	14.7		23	1050
E-2	SUCT. FROM RHR. HEAT EXCH. REAC. & SUPPRESSION POOL AT LOW PRESSURE (REACTOR PRESSURE = 150 PSIA)	FLOW (SEE NOTE 1)	—	—		—	16	266	266	250	250	—	—		5.10	16
		TEMPERATURE (F)	140/40	—		—	140/40	140/40	140/40	140/40	140/40	—	140/40		235/60	140/40
		PRESSURE (PSIA)	14.7	—		—	65	60	184	177	165	—	14.7		23	184
F	TEST MODE: SUCT. FROM CNDS. STG., REAC. AT HIGH PRESS. SUPPR. POOL AT LOW PRESS. (REACTOR PRESSURE = 1000 PSIA)	FLOW (SEE NOTE 1)	—	—	—	800	16	816	816	800	—	800	—		32.10	16
		TEMPERATURE (F)	140/40	—	—	100/40	100/40	100/40	100/40	100/40	—	100/40	100/40		235/60	100/40
		PRESSURE (PSIA)	14.7	—	—	23	65	23	1234	1223	—	85	145.7		23	1234

PRIORITY DRAWING

No.	REVISIONS	DWN	REV	RES ENG	CHKD	APPR	DATE
007	AS-BUILT PER EC-59642	STP	N/A	N/A	WE	LJ	8-31-15
006	AS-BUILT PER SWO: CORRECT FIGURE NUMBER	WE	N/A	N/A	N/A	DH	6-18-01

Q

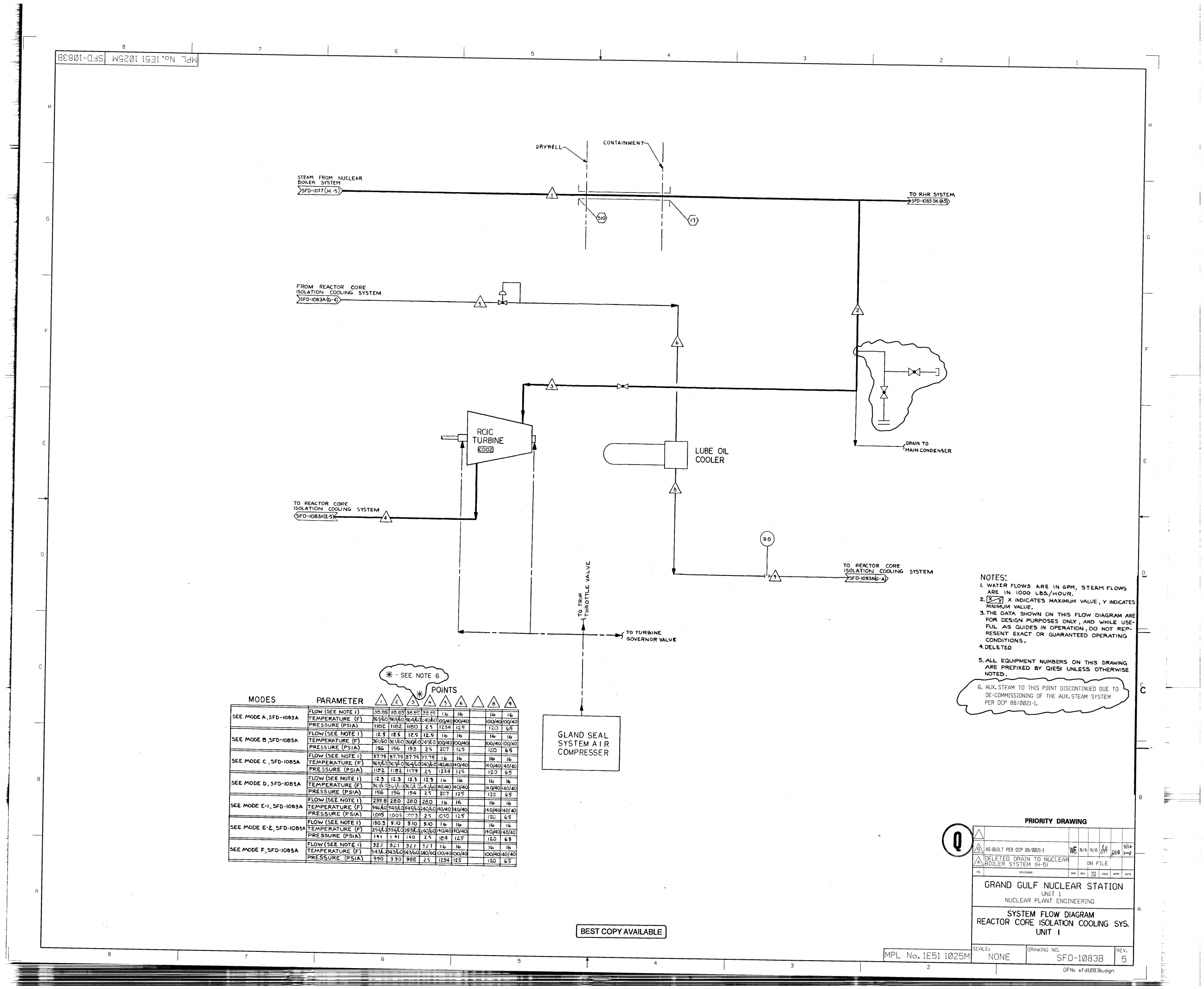
GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING

UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER – 05.4-012

SYSTEM FLOW DIAGRAM
REACTOR CORE ISOLATION COOLING
SYSTEM UNIT 1

MPL No. 1E51 1025M	SCALE: NONE	DRAWING No. SFD-1083A	REV. 007

DFN: sfd1083a.dgn



MODES	PARAMETER	POINTS 1	2	3	4	5	6		8	9
SEE MODE A, SFD-1083A	FLOW (SEE NOTE 1)	38.85	38.85	38.85	38.85	16	16		16	16
	TEMPERATURE (F)	565/60	565/60	564/60	240/60	100/40	100/40		100/40	100/40
	PRESSURE (PSIA)	1182	1182	1180	25	1234	125		120	65
SEE MODE B, SFD-1083A	FLOW (SEE NOTE 1)	12.5	12.5	12.5	12.5	16	16		16	16
	TEMPERATURE (F)	361/60	361/60	360/60	240/60	100/40	100/40		100/40	100/40
	PRESSURE (PSIA)	156	156	153	25	207	125		120	65
SEE MODE C, SFD-1083A	FLOW (SEE NOTE 1)	37.75	37.75	37.75	37.75	16	16		16	16
	TEMPERATURE (F)	565/60	565/60	564/60	240/60	140/40	140/40		140/40	140/40
	PRESSURE (PSIA)	1182	1182	1179	25	1234	125		120	65
SEE MODE D, SFD-1083A	FLOW (SEE NOTE 1)	12.3	12.3	12.3	12.3	16	16		16	16
	TEMPERATURE (F)	361/60	361/60	360/60	240/60	140/40	140/40		140/40	140/40
	PRESSURE (PSIA)	156	156	154	25	207	125		120	65
SEE MODE E-1, SFD-1083A	FLOW (SEE NOTE 1)	235.8	28.0	28.0	28.0	16	16		16	16
	TEMPERATURE (F)	546/60	545/60	545/60	240/60	140/40	140/40		140/40	140/40
	PRESSURE (PSIA)	1,005	1,005	1003	25	1050	125		120	65
SEE MODE E-2, SFD-1083A	FLOW (SEE NOTE 1)	130.3	5.10	5.10	5.10	16	16		16	16
	TEMPERATURE (F)	354/60	354/60	353/60	240/60	140/40	140/40		140/40	140/40
	PRESSURE (PSIA)	141	141	140	25	184	125		120	65
SEE MODE F, SFD-1083A	FLOW (SEE NOTE 1)	32.1	32.1	32.1	32.1	16	16		16	16
	TEMPERATURE (F)	543/60	543/60	543/60	240/60	100/40	100/40		100/40	140/40
	PRESSURE (PSIA)	990	990	988	25	1234	125		120	65

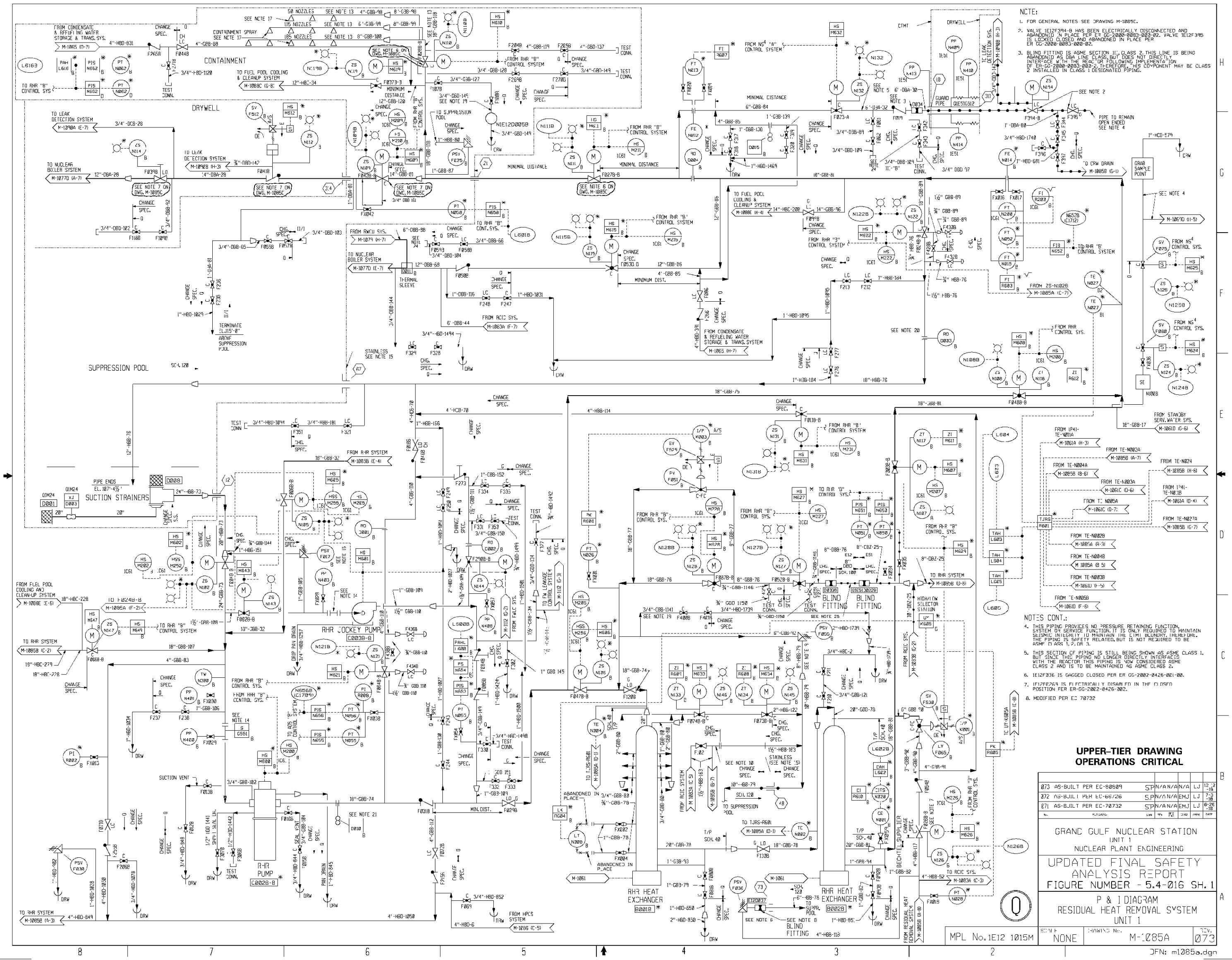
Figure 5.4-14

Deleted

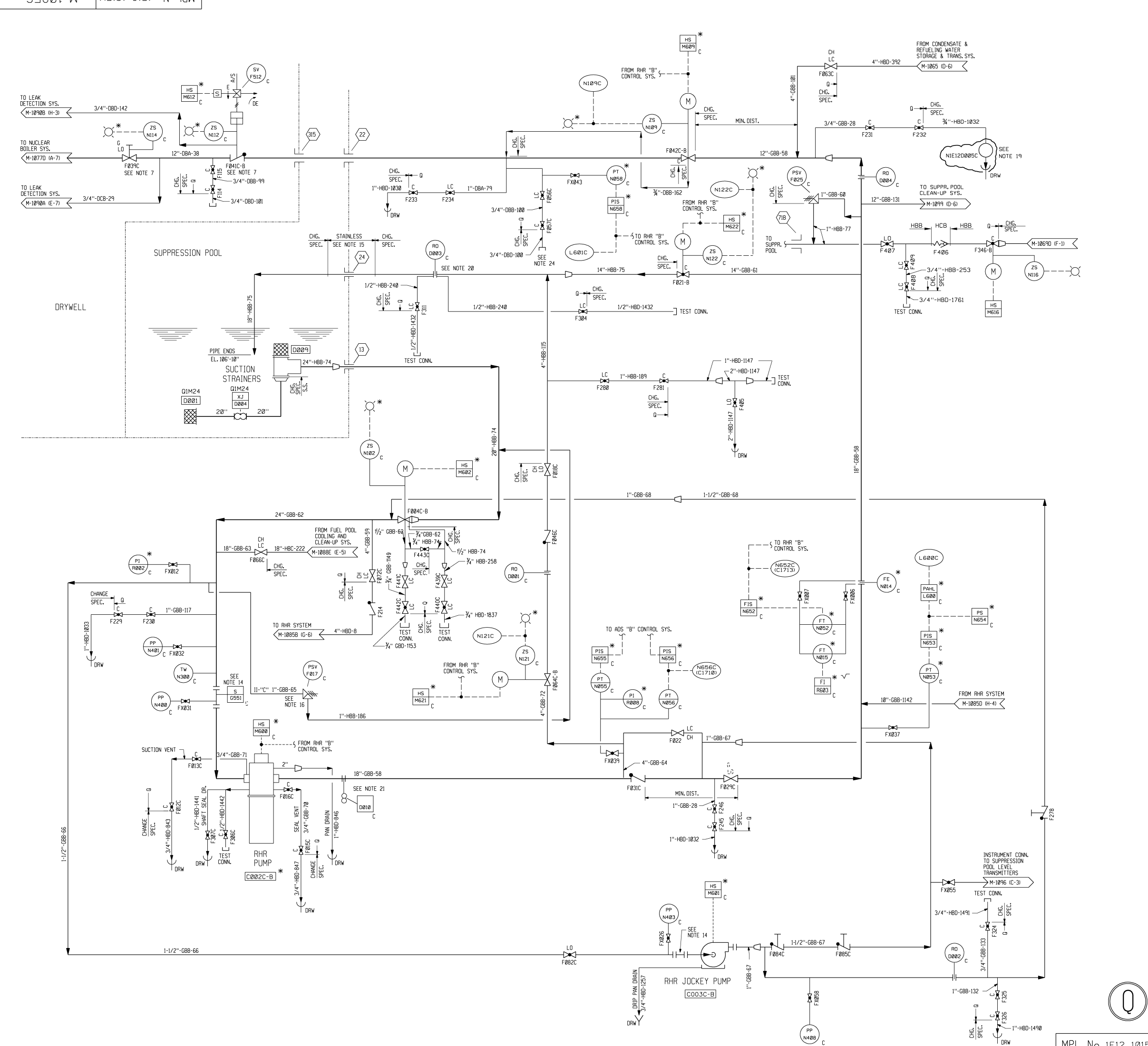
Figure 5.4-15

Deleted

Figure 5.4-016
Deleted


UPPER-TIER DRAWING
OPERATIONS CRITICAL
GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY
ANALYSIS REPORT
FIGURE NUMBER - 5.4-016 SH. 1
P & I DIAGRAM
RESIDUAL HEAT REMOVAL SYSTEM
UNIT 1
MPL No. 1E12 1015M
NONE
M-1085A
073
DFN: m1085a.dgn
RHR JOCKEY PUMP
RHR PUMP
RHR HEAT EXCHANGER
SUPPRESSION POOL
SUCTION STRAINERS
CONTAINMENT
DRYWELL
NOTE:
NOTES CONT.:

MPL No.1E12 1015M M-1085C



NOTES:

1. ALL EQUIPMENT NUMBERS ON THIS DRAWING ARE PREFIXED BY Q1E12 UNLESS OTHERWISE NOTED.
2. DELETED
3. THIS P&ID IS REDRAWN FROM G.E. P&ID No. 762E424BA REVISION 2.
4. THIS LINE IS 3/8" O.D., 304 STAINLESS STEEL TUBING WITH 0.065" WALL THICKNESS.
5. ALL INSTRUMENT NUMBERS ON THIS DRAWING ARE PREFIXED BY 1E12 UNLESS OTHERWISE NOTED.
6. VALVES F027A&B AND F028A&B ARE 600 LB. CARBON STEEL, CLASS II VALVES (EBB).
7. VALVES F039A, B & C, F041A, B & C, F042A, B, AND C ARE 600 LB. CARBON STEEL CLASS I VALVES (EBA).
8. INTERCONNECTION OF 18"-GBB-52 AND 14"-GBB-20 SHOULD BE AS CLOSE AS POSSIBLE TO F042A AND INTERCONNECTION OF 18"-GBB-118 AND 14"-GBB-81 SHOULD BE AS CLOSE AS POSSIBLE TO F042B.
9. DISCHARGE LINE FROM RELIEF VALVE SHALL SLOPE DOWNWARD CONTINUOUSLY TO SUPPRESSION POOL.
10. THE LENGTH OF PIPE INVOLVED IN THE VACUUM BREAKER ARRANGEMENT, FROM THE ATMOSPHERE TO EITHER VALVE F055A OR B DISCHARGE LINE SHALL NOT EXCEED 100 FEET.
11. VALVES F037A & B SHOULD BE INSTALLED SUCH THAT THE FLOW INDICATOR IS POINTED AWAY FROM THE CONTAINMENT WALL.
12. ALL PIPING 2" & SMALLER ON DWG. M-1085A AND C IS CLASSIFIED AS II-"C" R.L. ACCEPT AS NOTED. IF THE PIPE IS FLUSHED AFTER USE OF RHR, IT IS CLASSIFIED AS III-"B" R.L.
13. THE FOLLOWING PIPING IS TO BE GALVANIZED IN THE FIELD BEFORE BEING INSTALLED: GBB-52 (DOWNSTREAM OF VALVE F028A), GBB-55, GBB-54, GBB-53, GBB-118 (DOWNSTREAM OF VALVE F028B), GBB-98, GBB-99 AND GBB-100.
14. ALL START-UP STRAINERS HAVE BEEN REPLACED IN ACCORDANCE WITH THE LATEST REVISION OF 9645-MS-03 GENERAL NOTE 17.
15. FOR PENETRATION MATERIALS AND DETAILS SEE DWG. 9645-C-1004.
16. VALVES PSVF017A, PSVF017B AND PSVF017C SHALL BE INSTALLED ABOVE THE SUPPRESSION POOL WATER LEVEL EL.111'-10".
17. PIPING CLASSIFICATION GBB EXTENDS UP TO THE SPRAY NOZZLES CONNECTING NIPPLES. ASME SECTION III CODE BOUNDARY DOES NOT EXTEND BEYOND THIS POINT.
18. ALL PIPING 2" & SMALLER ON DWG. M-1085B IS CLASSIFIED AS A II-"C" OR III-"B" RADIATION LEVEL.
19. ROUTE TO THE NEAREST PLATFORM AND LOCATE VALVES SUCH THAT AN OPERATOR CAN REACH THE VALVES FROM THE PLATFORM. LOCATE SIGHT GLASS SUCH THAT THE OPERATOR CAN SEE EVIDENCE OF FLOW FROM THE VALVE LOCATION.
20. TESTABLE FLANGES WITH DOUBLE O-RINGS SHALL BE PROVIDED. INSTRUMENT TAPS SHALL BE IN ACCORDANCE WITH M-1312E.
21. SEE MNCR 93-0018
22. DELETED PER ER GG-2000-0083-000-02.
23. FI WITH √‾ SYMBOL DENOTES SQUARE ROOT SCALE ONLY.
24. FIRE HOSE CONNECTION INSTALLED FOR USE AS REACTOR VESSEL MAKEUP FROM P64 SYSTEM DURING ACCIDENT CONDITION.
25. ½" DIAMETER HOLES DRILLED IN PIPE FOR OVER PRESSURIZATION PROTECTION.

UPPER-TIER DRAWING OPERATIONS CRITICAL

No.	REVISIONS	DWN	REV	RES ENG	CHKD	APPR	DATE
020	AS-BUILT PER EC 25798	WE	N/A	N/A	STP	LJ	12-2-15
019	AS-BUILT PER EC-25800	STP	N/A	N/A	WE	LJ	7-17-15
018	AS-BUILT PER EC 30327	WE	N/A	N/A	STP	CW	6-23-11
017	AS-BUILT PER DRN 05-1064	WE	N/A	N/A	STP	[illegible]	2-9-06
016	AS-BUILT PER ER GG-2000-0118-000-00	SIGN-OFF ON RECORD					

GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING

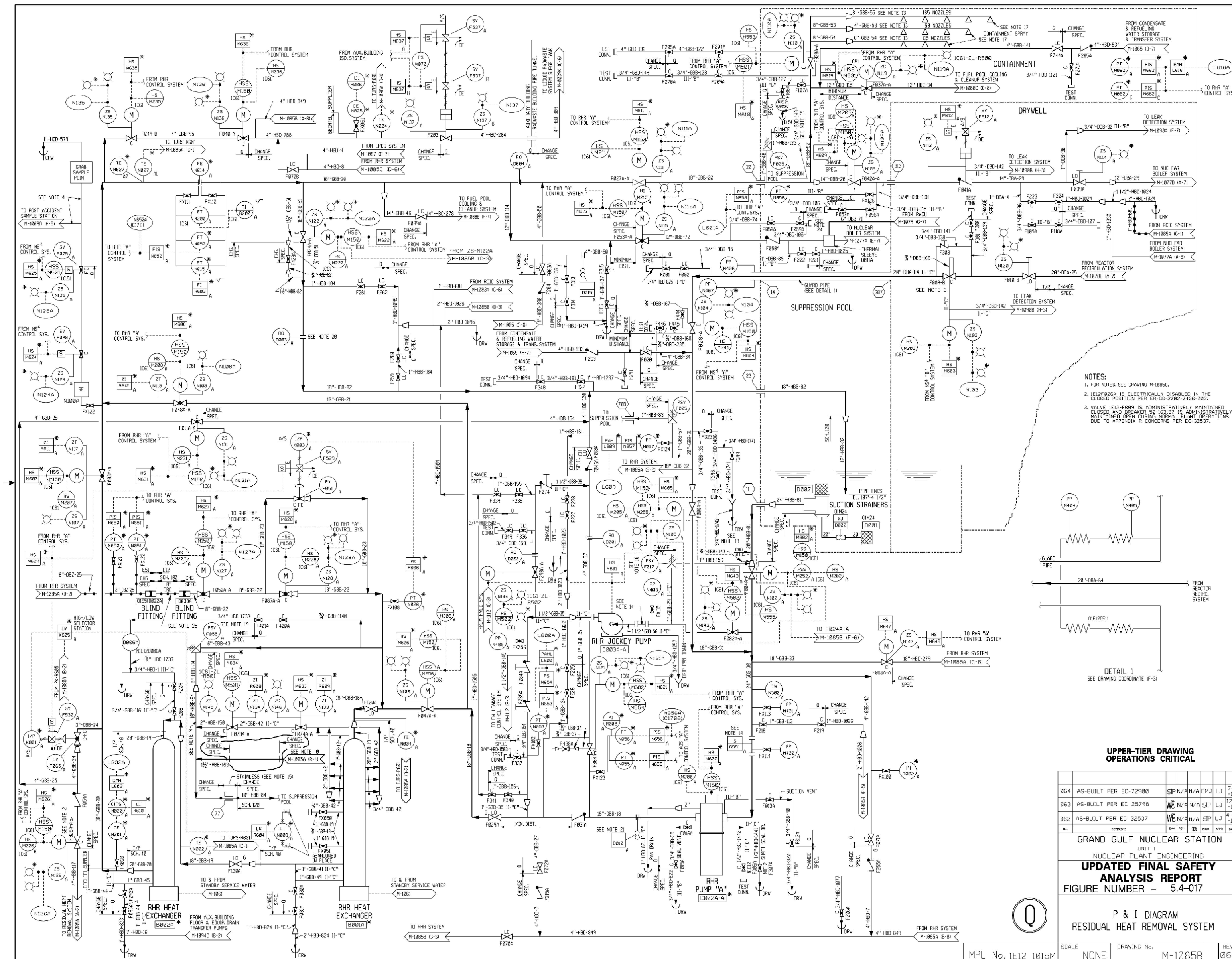
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER – 5.4-016-02

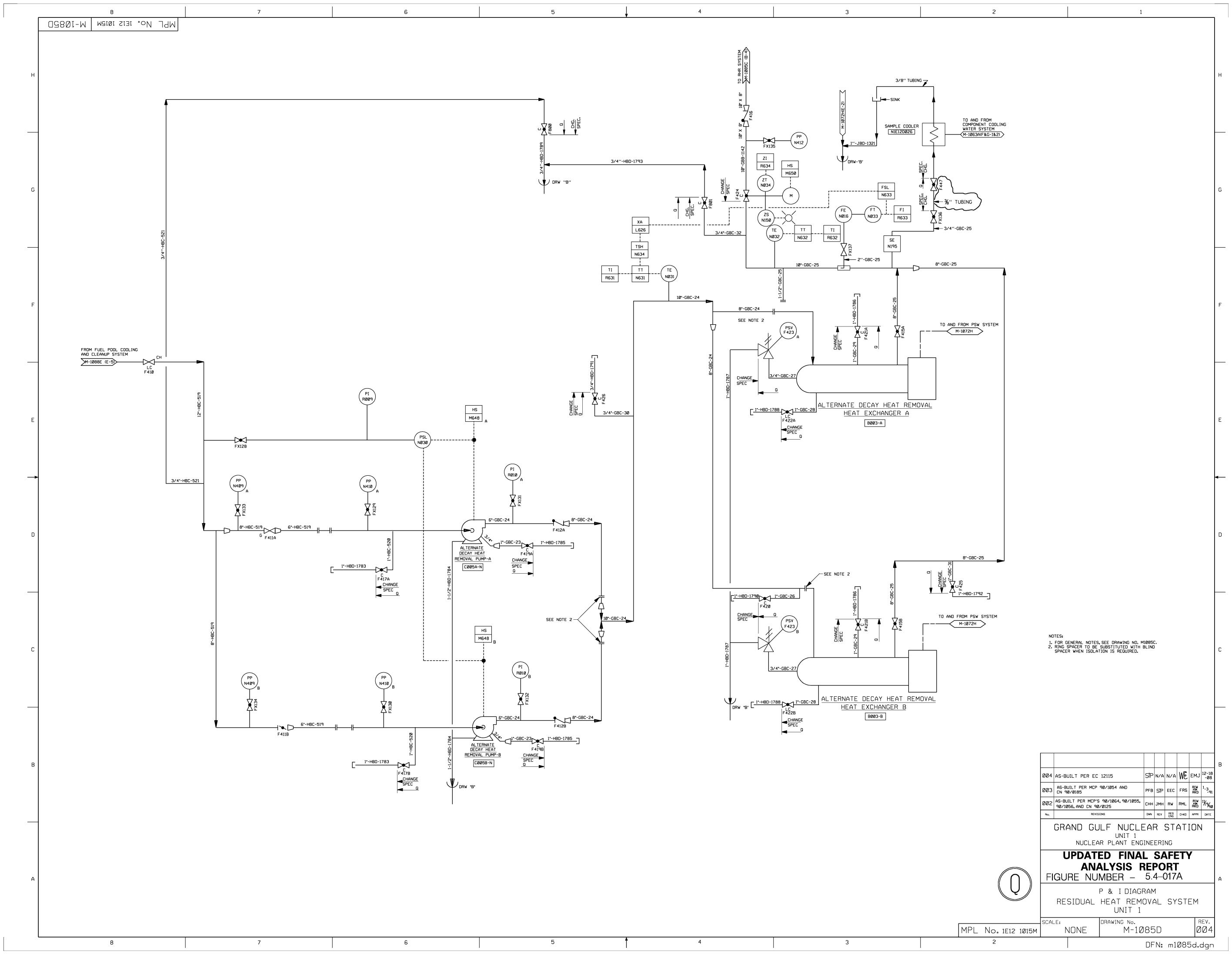
P & I DIAGRAM
RESIDUAL HEAT REMOVAL SYSTEM
UNIT 1

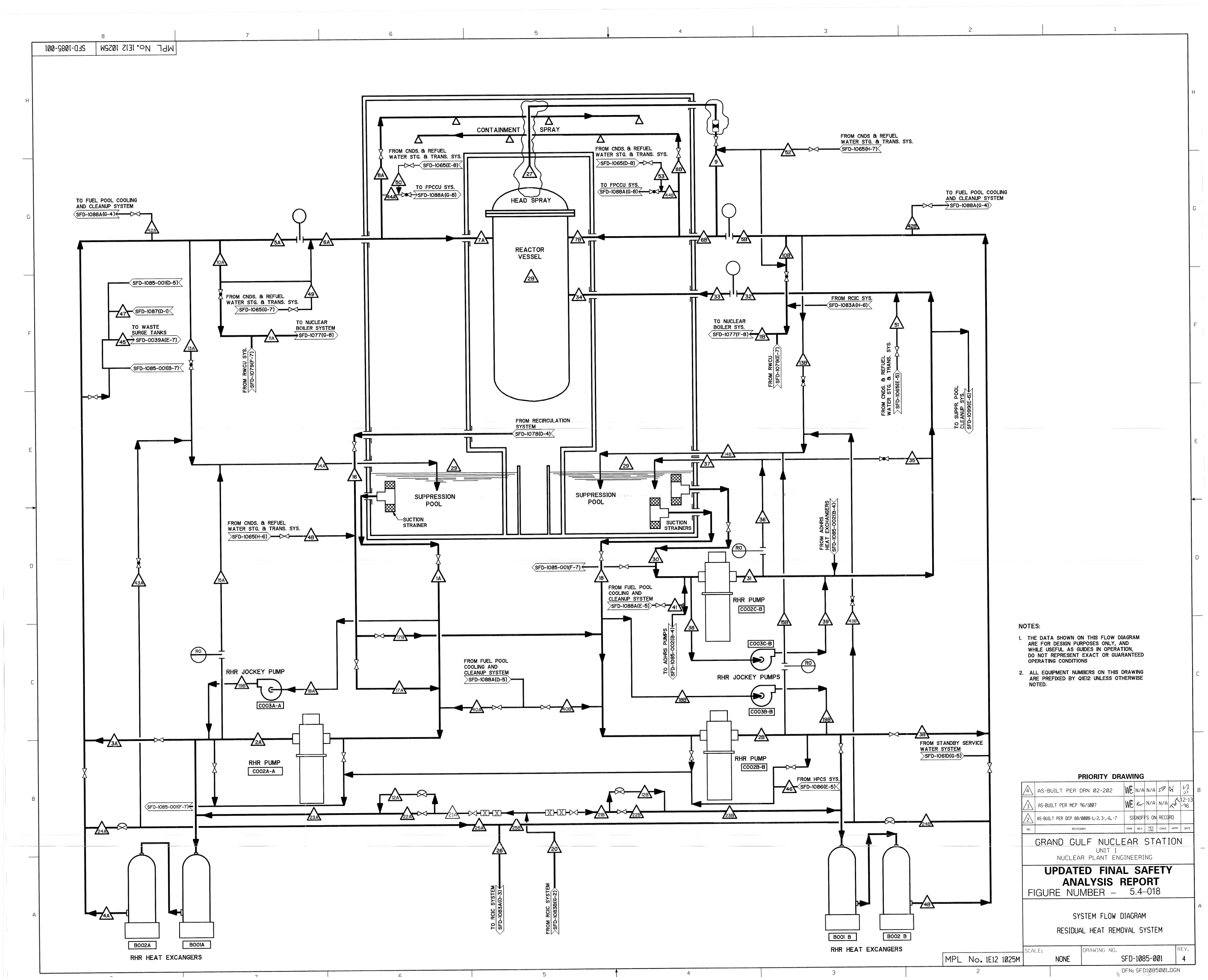
Q

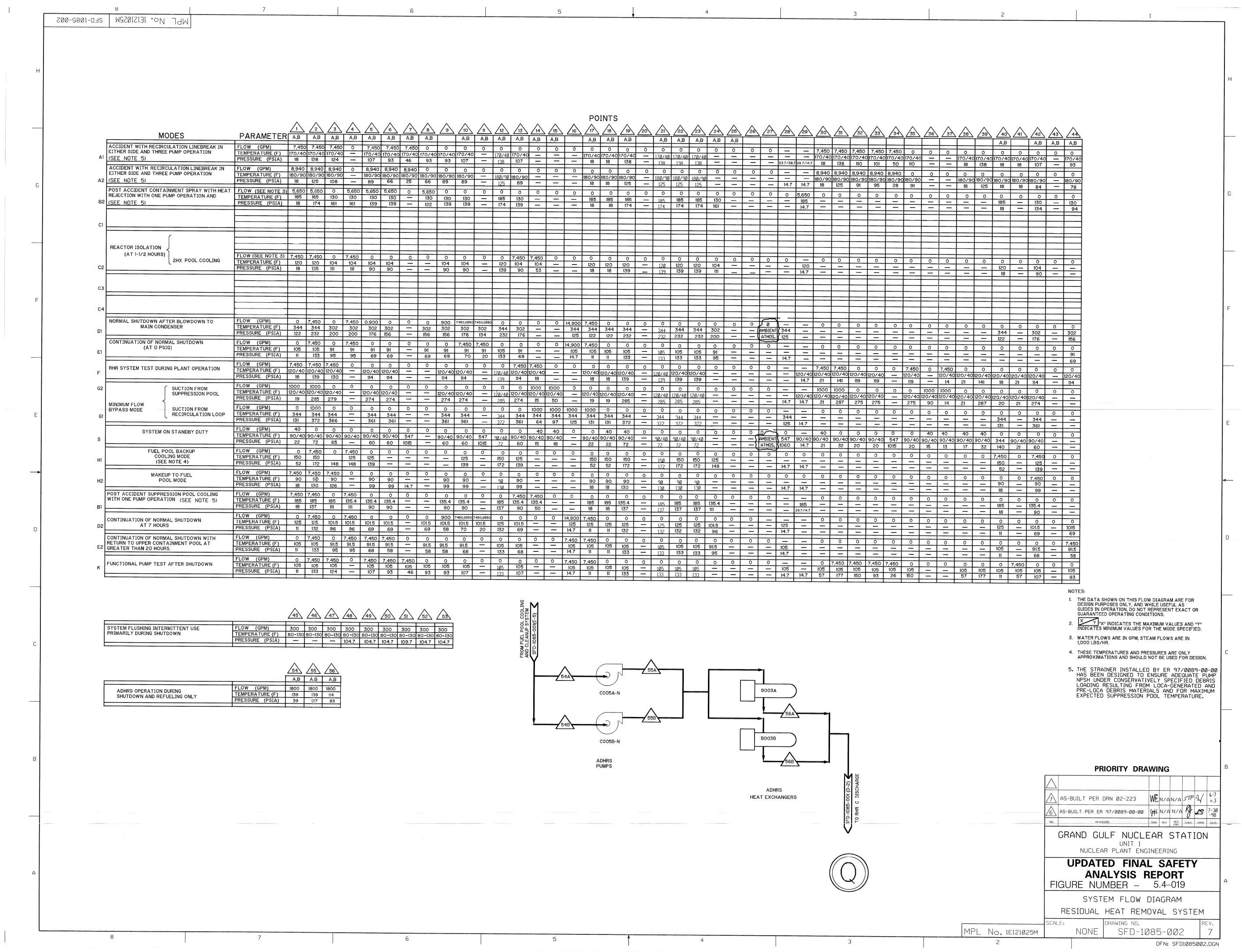
MPL No. 1E12 1015M | SCALE NONE | DRAWING No. M-1085C | REV. 020

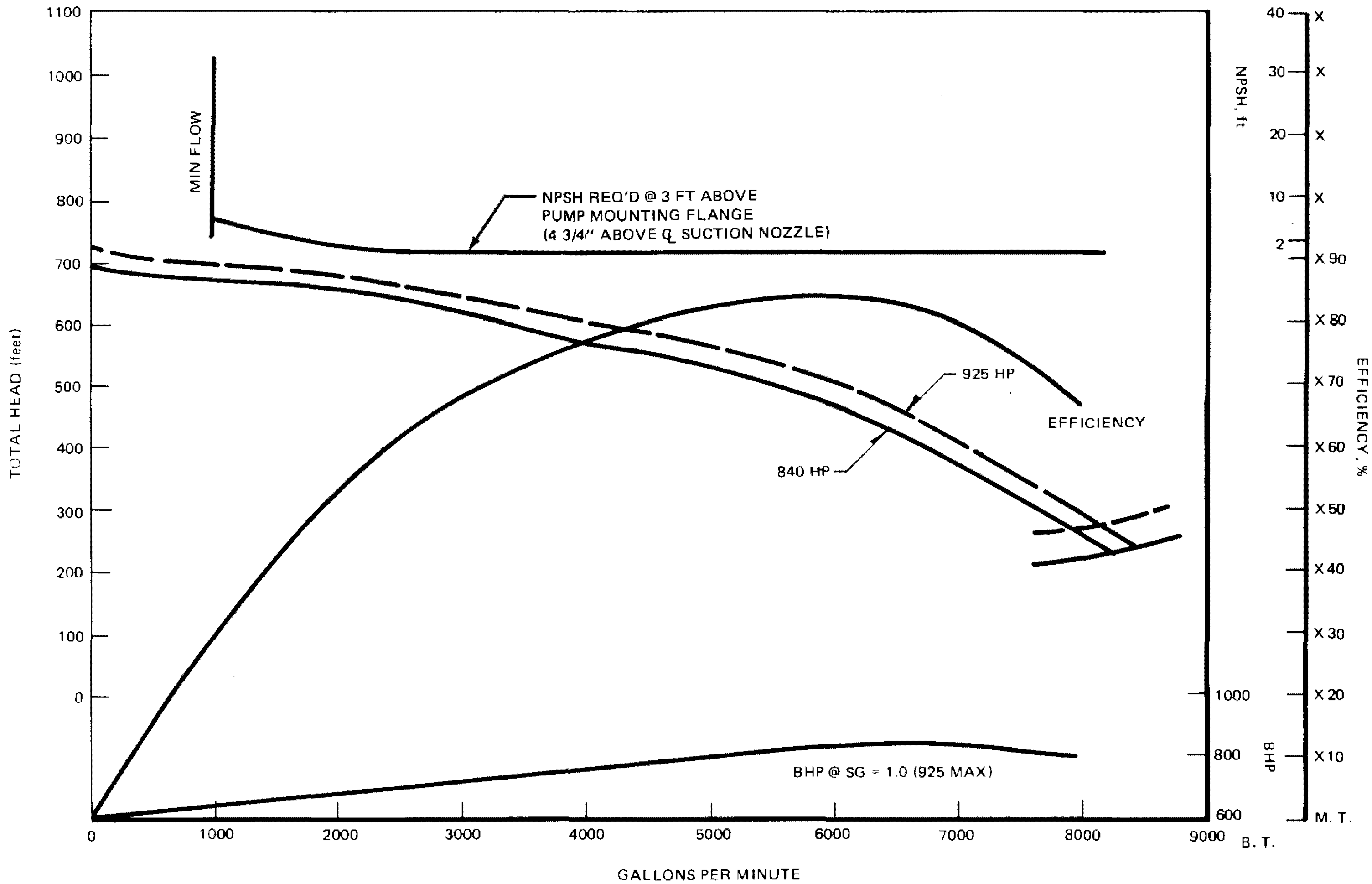
DFN: m1085c.dgn


CONTAINMENT
DRYWELL
SUPPRESSION POOL
RHR HEAT EXCHANGER B002A
RHR HEAT EXCHANGER B001A
RHR PUMP "A" C002A-A
RHR JOCKEY PUMP C003A-A
SUCTION STRAINERS
NOTES:
1. FOR NOTES, SEE DRAWING M-1085C.
2. 1E12F026A IS ELECTRICALLY DISABLED IN THE CLOSED POSITION PER ER-GG-2002-0426-002.
3. VALVE 1E12-F009 IS ADMINISTRATIVELY MAINTAINED CLOSED AND BREAKER 52-163:37 IS ADMINISTRATIVELY MAINTAINED OPEN DURING NORMAL PLANT OPERATIONS DUE TO APPENDIX R CONCERNS PER EC-32537.
DETAIL 1
SEE DRAWING COORDINATE (F-3)
UPPER-TIER DRAWING
OPERATIONS CRITICAL
064 AS-BUILT PER EC-72900 STP N/A N/A EMJ LJ 7-4-18
063 AS-BUILT PER EC 25798 WE N/A N/A STP LJ 12-2-15
062 AS-BUILT PER EC 32537 WE N/A N/A STP LJ 4-21-12
No. REVISIONS DWN REV RES ENG CHKD APPR DATE
GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER – 5.4–017
P & I DIAGRAM
RESIDUAL HEAT REMOVAL SYSTEM
MPL No. 1E12 1015M
SCALE NONE
DRAWING No. M-1085B
REV. 064
DFN: m1085b.dgn

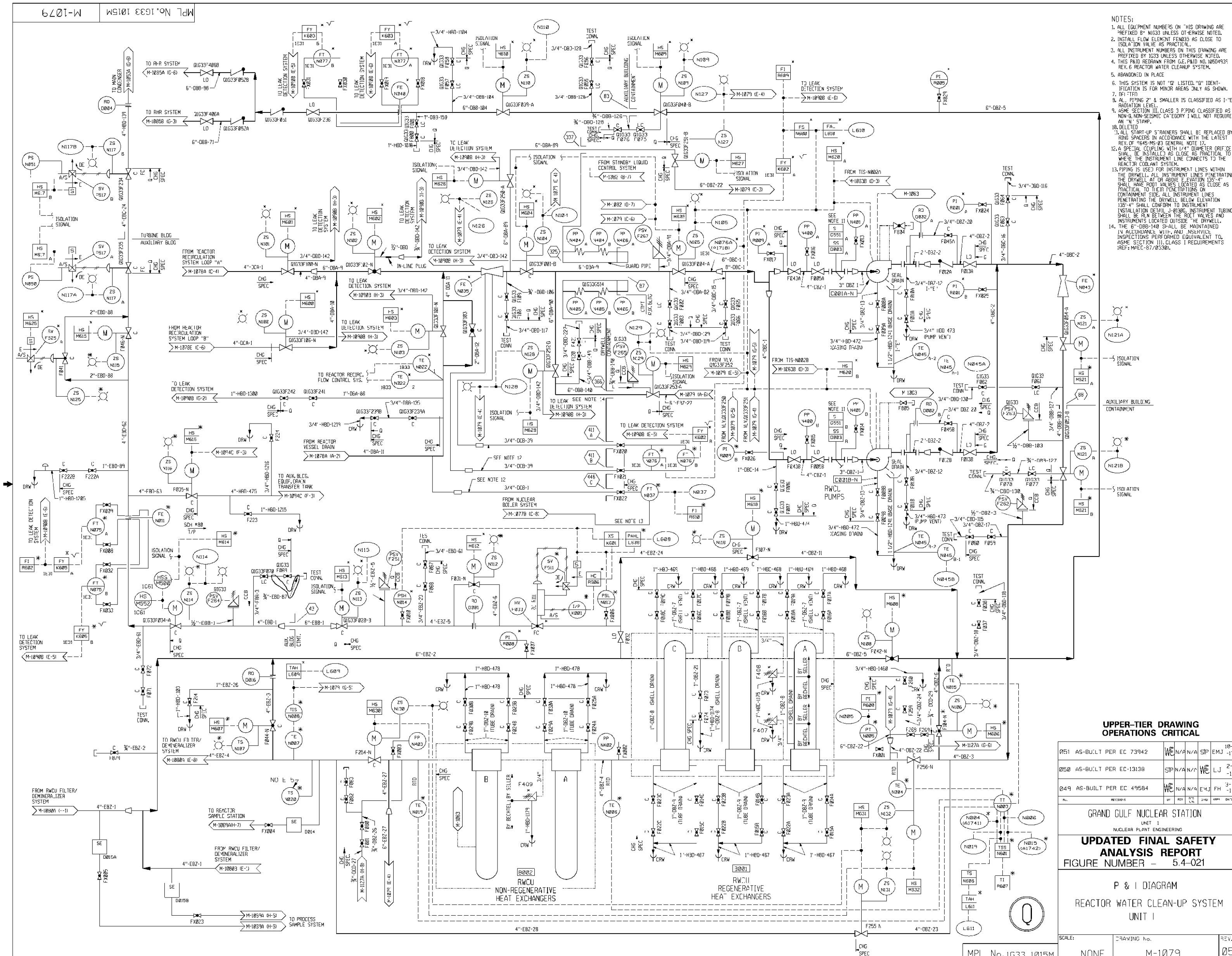

MPL No. 1E12 1015M M-1085D
FROM FUEL POOL COOLING AND CLEANUP SYSTEM
ALTERNATE DECAY HEAT REMOVAL PUMP-A
ALTERNATE DECAY HEAT REMOVAL PUMP-B
ALTERNATE DECAY HEAT REMOVAL HEAT EXCHANGER A
ALTERNATE DECAY HEAT REMOVAL HEAT EXCHANGER B
TO AND FROM PSW SYSTEM
SAMPLE COOLER
TO AND FROM COMPONENT COOLING WATER SYSTEM
SEE NOTE 2
NOTES:
1. FOR GENERAL NOTES, SEE DRAWING NO. M1085C.
2. RING SPACER TO BE SUBSTITUTED WITH BLIND SPACER WHEN ISOLATION IS REQUIRED.
004 AS-BUILT PER EC 12115 STP N/A N/A WE EMJ 12-18-08
003 AS-BUILT PER MCP 90/1054 AND CN 90/0185 PFB STP EEC FRS RIW FOR RKD 1-3-91
002 AS-BUILT PER MCP'S 90/1064, 90/1055, 90/1056, AND CN 90/0125 CHH JMH RW RML RIW FOR RKD 11/19/90
No. REVISIONS DWN REV RES ENG CHKD APPR DATE
GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER – 5.4-017A
P & I DIAGRAM
RESIDUAL HEAT REMOVAL SYSTEM
UNIT 1
SCALE: NONE
DRAWING No. M-1085D
REV. 004
MPL No. 1E12 1015M
DFN: m1085d.dgn

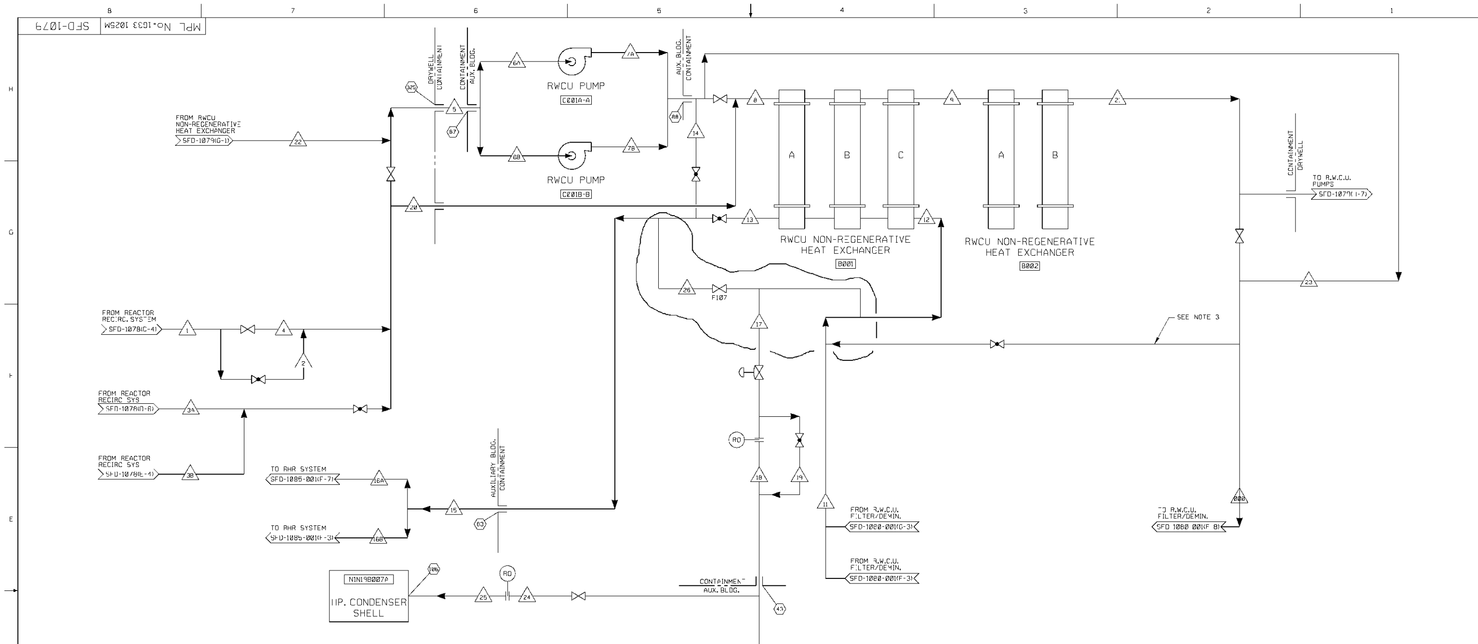

CONTAINMENT SPRAY
HEAD SPRAY
REACTOR VESSEL
SUPPRESSION POOL
SUCTION STRAINER
SUCTION STRAINERS
RHR JOCKEY PUMP
C003A-A
RHR PUMP
C002A-A
RHR JOCKEY PUMPS
C003C-B
C003B-B
C002C-B
C002B-B
B002A
B001A
B001 B
B002 B
RHR HEAT EXCANGERS
RHR HEAT EXCANGERS
NOTES:
1. THE DATA SHOWN ON THIS FLOW DIAGRAM ARE FOR DESIGN PURPOSES ONLY, AND WHILE USEFUL AS GUIDES IN OPERATION, DO NOT REPRESENT EXACT OR GUARANTEED OPERATING CONDITIONS
2. ALL EQUIPMENT NUMBERS ON THIS DRAWING ARE PREFIXED BY Q1E12 UNLESS OTHERWISE NOTED.
PRIORITY DRAWING
4 AS-BUILT PER DRN 02-202
3 AS-BUILT PER MCP 96/1007
2 AS-BUILT PER DCP 88/0008-1,-2.3-,-6,-7 SIGNOFFS ON RECORD
NO. REVISIONS DWN REV RES ENG CHKD APPR DATE
GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER – 5.4-018
SYSTEM FLOW DIAGRAM
RESIDUAL HEAT REMOVAL SYSTEM
SCALE: NONE
DRAWING NO. SFD-1085-001
REV. 4
MPL No. 1E12 1025M
DFN: SFD1085001.DGN


MPL No. 1E121025M SFD-1085-002
POINTS
MODES
PARAMETER
PRIORITY DRAWING
GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER – 5.4-019
SYSTEM FLOW DIAGRAM
RESIDUAL HEAT REMOVAL SYSTEM
SCALE: NONE
DRAWING NO. SFD-1085-002
REV. 7
ADHRS PUMPS
ADHRS HEAT EXCHANGERS
C005A-N
C005B-N
B003A
B003B
NOTES:
1. THE DATA SHOWN ON THIS FLOW DIAGRAM ARE FOR DESIGN PURPOSES ONLY, AND WHILE USEFUL AS GUIDES IN OPERATION, DO NOT REPRESENT EXACT OR GUARANTEED OPERATING CONDITIONS.
3. WATER FLOWS ARE IN GPM, STEAM FLOWS ARE IN 1000 LBS/HR.
4. THESE TEMPERATURES AND PRESSURES ARE ONLY APPROXIMATIONS AND SHOULD NOT BE USED FOR DESIGN.
5. THE STRAINER INSTALLED BY ER 97/0009-00-00 HAS BEEN DESIGNED TO ENSURE ADEQUATE PUMP NPSH UNDER CONSERVATIVELY SPECIFIED DEBRIS LOADING RESULTING FROM LOCA-GENERATED AND PRE-LOCA DEBRIS MATERIALS AND FOR MAXIMUM EXPECTED SUPPRESSION POOL TEMPERATURE.



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	RHR PUMP CHARACTERISTICS CURVES FIGURE 5.4-20


UPPER-TIER DRAWING OPERATIONS CRITICAL
051 AS-BUILT PER EC 73942
050 AS-BUILT PER EC 13138
049 AS-BUILT PER EC 49584
GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER - 5.4-021
P & I DIAGRAM
REACTOR WATER CLEAN-UP SYSTEM
UNIT I
MPL No.1G33 1015M
NONE
M-1079
051
DFN: m1079.dgn
RWCU
NON-REGENERATIVE
HEAT EXCHANGERS
RWCU
REGENERATIVE
HEAT EXCHANGERS
RWCU PUMPS
NOTES:



NOTES:

1. ALL EQUIPMENT NUMBERS ON THIS DRAWING ARE PREFIXED BY N1G33 UNLESS OTHERWISE NOTED.
2. THE DATA SHOWN ON THIS FLOW DIAGRAM ARE FOR DESIGN PURPOSES ONLY, AND WHILE USEFUL AS GUIDES IN OPERATION, DO NOT REPRESENT EXACT OR GUARANTEED OPERATING CONDITIONS.
3. THIS FLOW PATH USED AS ALTERNATE DURING STARTUP MODE IF FILTER/DEMIN-ERALIZERS ARE BYPASSED DURING STARTUP OPERATION.
4. THE 1G33F107 IS THROTTLED IN VARIOUS CONDITION DURING OPERATION. FLOW SHALL BE MAINTAINED LESS THAN OR EQUAL TO 460 GPM AT ALL TIMES.

POINTS

MODES	PARAMETER	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
				A, B			A, B	A, B									A, B										
NORMAL PLANT OPERATION (FLOW THRU HEAT EXCHANGERS PRIOR TO PUMPS)	FLOW (GPM)	63	63	204/204	0	360	180/180	180/180	472	374	360	360	360	426	0	426	213/213	0	0	0	472	360	360	360	0	0	*
	TEMPERATURE (F)	533	533	533	—	120	120	120	533	233	120	120	120	437	—	437	437	—	—	—	533	120	120	120	—	—	*
	PRESSURE (PSIA)	1062	1058	1060	—	1013	1022	1268	1023	1013	1215	1119	1124	1114	—	1128	1121	—	—	—	1040	1001	1013	1224	—	—	*
HOT STANDBY OPERATION (WITH LOSS OF OFF-SITE POWER)	FLOW (GPM)	179	0	150/150	179	479	240/240	240/240	0	0	0	0	0	0	479	479	240/240	0	0	0	0	0	0	0	0	0	*
	TEMPERATURE (F)	540	—	540/540	540	540	540/540	540/540	—	—	—	—	—	—	540	540	540/540	—	—	—	—	—	—	—	—	—	*
	PRESSURE (PSIA)	994	—	995	994	975	982	1159	—	—	—	—	—	—	1122	976	968	—	—	—	—	—	—	—	—	—	*
BLOWDOWN OPERATION HOT STANDBY	FLOW (GPM)	30	30	43/43	0	87	87/0	87/0	116	116	87	87	0	0	0	0	0/0	87	87	0	116	87	87	87	87	87	*
	TEMPERATURE (F)	540	540	540	—	100	100	100	540	540	100	100	—	—	—	—	—/—	100	100	—	540	100	100	102	100	120	*
	PRESSURE (PSIA)	1060	1060	1060	—	1049	1059	1311	1036	1036	1278	1219	—	—	—	—	—	1233	1.7	—	1049	1053	1049	1283	7.7	1.7	*
REFUELING OPERATIONS WITH MAXIMUM BYPASS		35	35	162/162	2	360	180/180	180/180	360	360	360	360	0	0	0	0	0	360	0	360	0	360	0	0	360	360	*
		125	125	125	-	125	125/125	125/125	125	125	125	125	—	—	—	—	—	120	—	120	—	120	-	-	120		*
		52	50	50	-	27	37	282	242	236	216	157	—	—	—	—	—	146	—	116	—	208	-	-	102	6	*
REFUELING OPERATION NO BYPASS	FLOW (GPM)	35	35	162/162	0	360	180/180	180/180	360	360	360	360	360	360	0	360	180/180	0	0	2	0	360	0	0	0	0	*
	TEMPERATURE (F)	125	125	125	—	125	125/125	125/125	125	125	125	125	125	125	—	125	125/125	—	—	—	—	125	—	—	—	—	*
	PRESSURE (PSIA)	52	50	50	—	27	37	282	242	236	216	157	163	153	—	169	164	—	—	—	—	229	—	—	—	—	*
PLANT STARTUP OPERATION MAXIMUM BYPASS	FLOW (GPM)	44	44	165/165	0	374	187/187	187/187	374	374	360	360	0	2	0	0	0	360	0	360	0	360	0	0	360	360	*
	TEMPERATURE (F)	233	233	233	—	233	233	233	233	233	120	120	—	—	—	—	—	120	—	120	—	120	—	—	120	120	*
	PRESSURE (PSIA)	43	40	39	—	18	27	262	222	216	195	136	—	—	—	—	—	146	—	116	—	208	—	—	102	6	*

SEE NOTE 4

PRIORITY DRAWING

No.	REVISIONS	DWN	REV	RSP ENG	CHKD	APPR	DATE
005	AS-BUILT PER EC-70646	STP	N/A	N/A	WE	EMJ	5-25-17
004	INCORP. DCP 82/4056 AS BUILT REF. NPESC 84/0198	SIGN-OFF ON RECORD					
003	SE REV. NOTICE 9645-SFD-1079-3	SIGN-OFF ON RECORD					

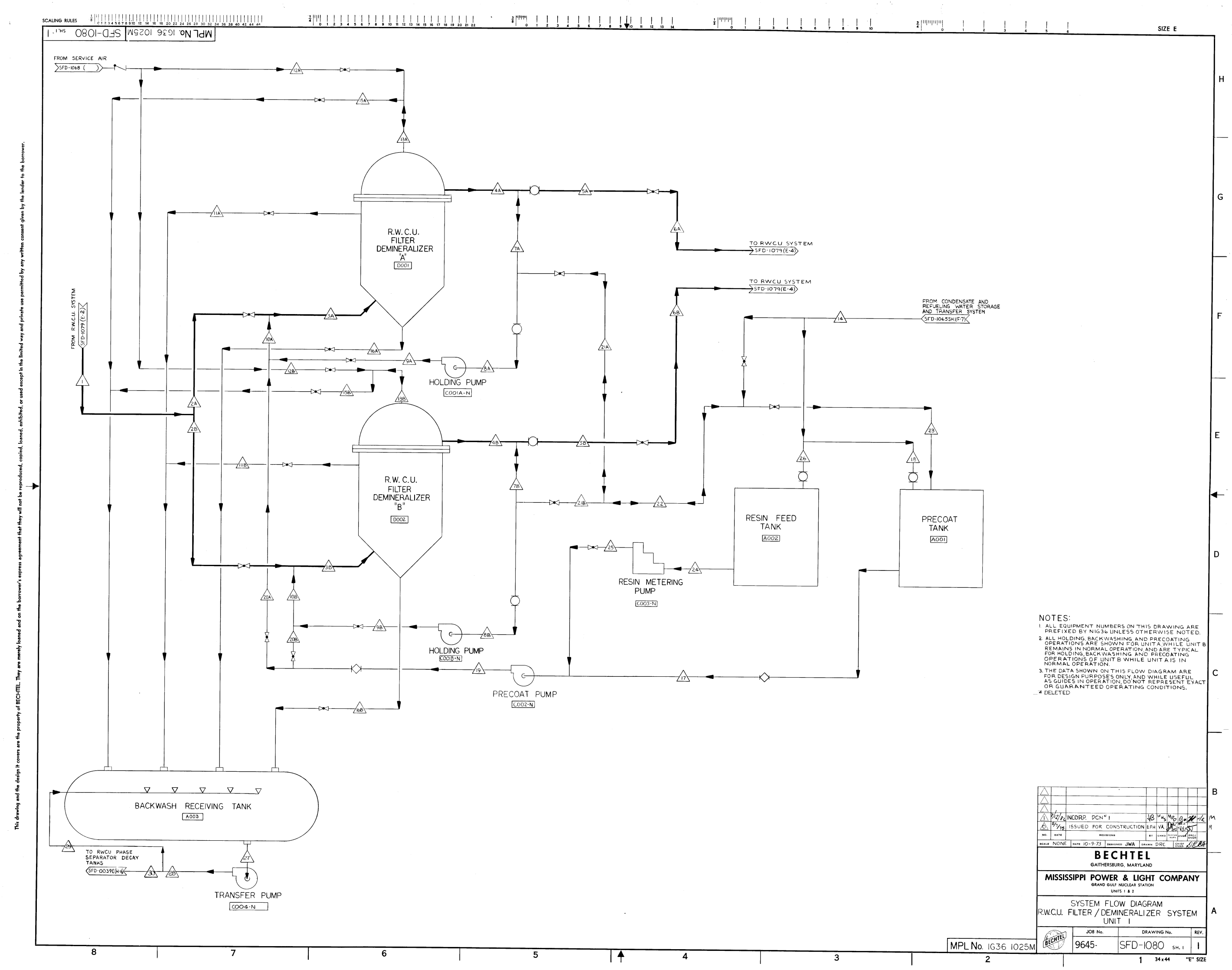
GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING

UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER – 05.4–022

SYSTEM FLOW DIAGRAM
REACTOR WATER CLEANUP SYSTEM
UNIT 1

MPL No. 1G33 1025M | SCALE: NONE | DRAWING No. SFD-1079 | REV. 005

DFN: sfd1079.dgn


MPL No. 1G36 1025M
SFD-1080
FROM SERVICE AIR
R.W.C.U. FILTER DEMINERALIZER "A"
D001
R.W.C.U. FILTER DEMINERALIZER "B"
D002
TO RWCU SYSTEM
SFD-1079(E-4)
FROM RWCU SYSTEM
FROM CONDENSATE AND REFUELING WATER STORAGE AND TRANSFER SYSTEM
HOLDING PUMP
C001A-N
HOLDING PUMP
C001B-N
RESIN FEED TANK
A002
PRECOAT TANK
A001
RESIN METERING PUMP
C003-N
PRECOAT PUMP
C002-N
BACKWASH RECEIVING TANK
A003
TO RWCU PHASE SEPARATOR DECAY TANKS
TRANSFER PUMP
C004-N
NOTES:
1. ALL EQUIPMENT NUMBERS ON THIS DRAWING ARE PREFIXED BY N1G36 UNLESS OTHERWISE NOTED.
2. ALL HOLDING, BACKWASHING AND PRECOATING OPERATIONS ARE SHOWN FOR UNIT A WHILE UNIT B REMAINS IN NORMAL OPERATION AND ARE TYPICAL FOR HOLDING, BACKWASHING AND PRECOATING OPERATIONS OF UNIT B WHILE UNIT A IS IN NORMAL OPERATION.
3. THE DATA SHOWN ON THIS FLOW DIAGRAM ARE FOR DESIGN PURPOSES ONLY AND WHILE USEFUL AS GUIDES IN OPERATION, DO NOT REPRESENT EXACT OR GUARANTEED OPERATING CONDITIONS.
4. DELETED
INCORP. PCN 1
ISSUED FOR CONSTRUCTION
BECHTEL
GAITHERSBURG, MARYLAND
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
SYSTEM FLOW DIAGRAM
R.W.C.U. FILTER / DEMINERALIZER SYSTEM
UNIT 1
9645-
SFD-1080
SIZE E

MPL No. 1G36 1025M SFD-1080 SH 2 1

POINTS

MODE	SUB-MODE	PARAMETER	1	2 (A,B)	3 (A,B)	4 (A,B)	5 (A,B)	6 (A,B)	7 (A,B)	8 (A,B)	9 (A,B)	10 (A,B)	11 (A,B)	12 (A,B)	13 (A,B)	14	15 (A,B)	16	17	18	19	20	21 (A,B)	22 (A,B)	23	24	25	26
UNITS A&B IN OPERATION (SEE NOTES 1&2)	NORMAL OPERATION	FLOW (GPM)	360	180/180	180/180	180/180	180/180	180/180	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		TEMPERATURE (F)	120	120/120	120/120	120/120	120/120	120/120	-/-	-/-	-/-	-/-	-/-	-/-	-/-	–	-/-	-/-	-/-	–	-/-	-/-	-/-	–	–	–	–	–
		PRESSURE (PSIG)	1150	1150	1139	1119	1107	1091	-/-	-/-	-/-	-/-	-/-	-/-	-/-	–	-/-	-/-	-/-	–	-/-	-/-	-/-	–	–	–	–	–
HOLDING OF UNIT A, WHILE UNIT B REMAINS IN OPN. (SEE NOTES 1&2)	HOLD	FLOW (GPM)	180	0/180	85/180	85/180	0/180	0/180	85/0	85/0	85/0	85/0	0/0	0/0	0/0	0	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		TEMPERATURE (F)	120	-/120	120/120	120/120	-/120	-/120	80-120/-	80-120/-	80-120/-	80-120/-	-/-	-/-	-/-	–	-/-	-/-	–	–	–	-/-	-/-	–	–	–	–	–
		PRESSURE (PSIG)	1150	–	1139	1134	–	–	1134	1132	1164	1140	-/-	-/-	-/-	–	-/-	-/-	–	–	–	-/-	-/-	–	–	–	–	–
BACKWASHING OF UNIT A, WHILE UNIT B REMAINS IN OPERATION (SEE NOTES 1,2,&7)	DOME DRAIN	H2O FLOW (GPM)	180	0/180	0/180	0/180	0/180	0/180	0/0	0/0	0/0	0/0	60/0	0/0	0/0	0	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		AIR FLOW (SCFM)	0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	54/0	54/0	0	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		TEMPERATURE (F)	120	-/120	-/120	-/120	-/120	-/120	-/-	-/-	-/-	-/-	120/-	60/-	60/-	–	-/-	-/-	–	–	–	-/-	-/-	–	–	–	–	–
		PRESSURE (PSIG)	1150	–	–	–	–	–	-/-	-/-	-/-	-/-	100	100	100	–	-/-	-/-	–	–	–	-/-	-/-	–	–	–	–	–
		DURATION (MINUTES)	–	–	–	–	–	–	–	–	–	–	3	3	3	–	–	–	–	–	–	–	–	–	–	–	–	–
	AIR PRESSURIZE	H2O FLOW (GPM)	180	0/180	0/180	0/180	0/180	0/180	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		AIR FLOW (SCFM)	0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	54/0	54/0	0	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		TEMPERATURE (F)	120	-/120	-/120	-/120	-/120	-/120	-/-	-/-	-/-	-/-	-/-	60/-	60/-	–	-/-	-/-	–	–	–	-/-	-/-	–	–	–	–	–
		PRESSURE (PSIG)	1150	–	–	–	–	–	-/-	-/-	-/-	-/-	-/-	100	100	–	-/-	-/-	–	–	–	-/-	-/-	–	–	–	–	–
		DURATION (MINUTES)	–	–	–	–	–	–	–	–	–	–	–	3	3	–	–	–	–	–	–	–	–	–	–	–	–	–
	FIRST AIR BUMP & DRAIN (FOR STEP 16, SEE NOTE 6)	H2O FLOW (GPM)	180	0/180	0/180	0/180	0/180	0/180	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0	0/0	5000 PEAK	0	0	0	0/0	0/0	0	0	0	0	0
		AIR FLOW (SCFM)	0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	54/0	54/0	0	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		TEMPERATURE (F)	120	-/120	-/120	-/120	-/120	-/120	-/-	-/-	-/-	-/-	-/-	60/-	60/-	–	-/-	120/0	–	–	–	-/-	-/-	–	–	–	–	–
		PRESSURE (PSIG)	1150	–	–	–	–	–	-/-	-/-	-/-	-/-	-/-	100	100	–	-/-	0 to 100	–	–	–	-/-	-/-	–	–	–	–	–
		DURATION (MINUTES)	–	–	–	–	–	–	–	–	–	–	–	0.5	0.5	–	–	0.5	–	–	–	–	–	–	–	–	–	–
	FILL AND VENT	H2O FLOW (GPM)	180	0/180	0/180	560/180	0/180	0/180	560/0	0/0	0/0	0/0	0/0	0/0	0/0	560	0/0	0/0	0	0	0	0/0	560/0	560	0	0	0	0
		AIR FLOW (SCFM)	0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	73/0	0	73/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		TEMPERATURE (F)	120	-/120	-/120	80/120	-/120	-/120	80/-	-/-	-/-	-/-	-/-	-/-	60/-	80	60/-	-/-	–	–	–	-/-	80/-	80	–	–	–	–
		PRESSURE (PSIG)	1150	–	–	20	–	–	20	-/-	-/-	-/-	-/-	-/-	3	20	3	-/-	–	–	–	-/-	20	20	–	–	–	–
		DURATION (MINUTES)	–	–	–	1.0	–	–	1.0	–	–	–	–	–	1.0	1.0	1.0	–	–	–	–	–	1.0	1.0	–	–	–	–
	DOME DRAIN	H2O FLOW (GPM)	180	0/180	0/180	0/180	0/180	0/180	0/0	0/0	0/0	0/0	60/0	0/0	0/0	0	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		AIR FLOW (SCFM)	0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	54/0	54/0	0	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		TEMPERATURE (F)	120	-/120	-/120	-/120	-/120	-/120	-/-	-/-	-/-	-/-	120/-	60/-	60/-	–	-/-	-/-	–	–	–	-/-	-/-	–	–	–	–	–
		PRESSURE (PSIG)	1150	–	–	–	–	–	-/-	-/-	-/-	-/-	100	100	100	–	-/-	-/-	–	–	–	-/-	-/-	–	–	–	–	–
		DURATION (MINUTES)	–	–	–	–	–	–	–	–	–	–	3	3	3	–	–	–	–	–	–	–	–	–	–	–	–	–
	AIR PRESSURIZE	H2O FLOW (GPM)	180	0/180	0/180	0/180	0/180	0/180	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		AIR FLOW (SCFM)	0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	54/0	54/0	0	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		TEMPERATURE (F)	120	-/120	-/120	-/120	-/120	-/120	-/-	-/-	-/-	-/-	-/-	60/-	60/-	–	-/-	-/-	–	–	–	-/-	-/-	–	–	–	–	–
		PRESSURE (PSIG)	1150	–	–	–	–	–	-/-	-/-	-/-	-/-	-/-	100	100	–	-/-	-/-	–	–	–	-/-	-/-	–	–	–	–	–
		DURATION (MINUTES)	–	–	–	–	–	–	–	–	–	–	–	3	3	–	–	–	–	–	–	–	–	–	–	–	–	–
	SECOND AIR BUMP & DRAIN (FOR STEP 16, SEE NOTE 6)	H2O FLOW (GPM)	180	0/180	0/180	0/180	0/180	0/180	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0	0/0	5000 PEAK	0	0	0	0/0	0/0	0	0	0	0	0
		AIR FLOW (SCFM)	0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	54/0	54/0	0	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		TEMPERATURE (F)	120	0/120	0/120	0/120	0/120	0/120	-/-	-/-	-/-	-/-	-/-	60/-	60/-	–	-/-	80/-	–	–	–	-/-	-/-	–	–	–	–	–
		PRESSURE (PSIG)	1150	–	–	–	–	–	-/-	-/-	-/-	-/-	-/-	100	100	–	-/-	0 to 100	–	–	–	-/-	-/-	–	–	–	–	–
		DURATION (MINUTES)	–	–	–	–	–	–	–	–	–	–	–	0.5	0.5	–	–	0.5	–	–	–	–	–	–	–	–	–	–
	BACKWASH & DRAIN (FOR STEP 16, SEE NOTE 6)	H2O FLOW (GPM)	180	0/180	0/180	560/180	0/180	0/180	560/0	0/0	0/0	0/0	0/0	0/0	0/0	560	0/0	560/0	0	0	0	0/0	560/0	560	0	0	0	0
		AIR FLOW (SCFM)	0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		TEMPERATURE (F)	120	-/120	-/120	80/120	-/120	-/120	80/-	-/-	-/-	-/-	-/-	-/-	-/-	80	-/-	80/-	–	–	–	-/-	80/-	80	–	–	–	–
		PRESSURE (PSIG)	1150	–	–	20	–	–	20	-/-	-/-	-/-	-/-	-/-	-/-	20	-/-	0 to 20	–	–	–	-/-	20	20	–	–	–	–
		DURATION (MINUTES)	–	–	–	0.7	–	–	0.7	–	–	–	–	–	–	0.7	-/-	0.7	–	–	–	–	0.7	0.7	–	–	–	–
	FILL AND VENT	H2O FLOW (GPM)	180	0/180	0/180	560/180	0/180	0/180	560/0	0/0	0/0	0/0	0/0	0/0	0/0	560	0/0	0/0	0	0	0	0/0	560/0	560	0	0	0	0
		AIR FLOW (SCFM)	0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	0/0	73/0	0	73/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		TEMPERATURE (F)	120	-/120	-/120	80/120	-/-	-/120	80/-	-/-	-/-	-/-	-/-	-/-	60/-	80	60/-	-/-	–	–	–	-/-	80/-	80	–	–	–	–
		PRESSURE (PSIG)	1150	–	–	20	–	–	20	-/-	-/-	-/-	-/-	-/-	3	20	3	-/-	–	–	–	-/-	20	20	–	–	–	–
		DURATION (MINUTES)	–	–	–	1.0	–	–	1.0	–	–	–	–	–	1.0	1.0	1.0	–	–	–	–	–	1.0	1.0	–	–	–	–
SOLKA-FLOC PRECOAT (SEE NOTES 1,2,&7)	SOLKA-FLOC PRECOAT AND RETURN	FLOW (GPM)	180	0/180	170/180	170/180	0/180	0/180	170/0	0/0	0/0	170/0	0/0	0/0	0/0	0	0/0	0/0	170	0	170	170/0	170/0	170	170	0	0	0
		TEMPERATURE (F)	120	-/120	80/120	80/120	-/120	-/120	80/-	-/-	-/-	80/-	-/-	-/-	-/-	–	-/-	-/-	80	–	80	80/-	80/-	80	80	–	–	–
		PRESSURE (PSIG)	1150	–	40	40	–	–	40	-/-	-/-	40	-/-	-/-	-/-	–	-/-	-/-	40	–	40	40	40	40	40	–	–	–
		DURATION (MINUTES)	–	–	10	10	–	–	10	–	–	10	–	–	–	–	–	–	10	–	10	10	10	10	10	–	–	–
RESIN PRECOAT (SEE NOTES 1,2,&7)	RESIN PRECOAT AND RETURN	FLOW (GPM)	180	0/180	250/180	250/180	0/180	0/180	250/0	0/0	0/0	250/0	0/0	0/0	0/0	0	0/0	0/0	248	0	250	250/0	250/0	250	250	2	2	0
		TEMPERATURE (F)	120	-/120	80/120	80/120	-/120	-/120	80/-	-/-	-/-	80/-	-/-	-/-	-/-	–	-/-	-/-	80	–	80	80/-	80/-	80	80	80	80	–
		PRESSURE (PSIG)	1150	–	40	40	–	–	40	-/-	-/-	40	-/-	-/-	-/-	–	-/-	-/-	40	–	40	40	40	40	40	1	42	–
		DURATION (MINUTES)	–	–	30	30	–	–	30	–	–	30	–	–	–	–	–	–	30	–	30	30	30	30	30	30	30	–
HOLD PRECOAT/ HOLD UNTIL RETURN TO SERVICE (SEE NOTES 1,2,&7)	HOLD PRECOAT AND RETURN	FLOW (GPM)	180	0/180	175/180	175/180	0/180	0/180	175/0	0/0	0/0	175/0	0/0	0/0	0/0	0	0/0	0/0	175	0	175	175/0	175/0	175	175	0	0	0
		TEMPERATURE (F)	120	-/120	80/120	80/120	-/120	-/120	80/-	-/-	-/-	80/-	-/-	-/-	-/-	–	-/-	-/-	80	–	80	80/-	80/-	80	80	–	–	–
		PRESSURE (PSIG)	1150	–	40	40	–	–	40	-/-	-/-	40	-/-	-/-	-/-	–	-/-	-/-	40	–	40	40	40	40	40	–	–	–
	HOLD UNTIL RETURN TO SERVICE	FLOW (GPM)	180	0/180	85/180	85/180	0/180	0/180	85/0	85/0	85/0	85/0	0/0	0/0	0/0	0	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	0
		TEMPERATURE (F)	120	-/120	120/120	120/120	-/120	-/120	120/120	120/120	120/120	120/120	-/-	-/-	-/-	–	-/-	-/-	–	–	–	-/-	-/-	–	–	–	–	–
		PRESSURE (PSIG)	1150	–	60	56	–	–	56	54	86	61	-/-	-/-	-/-	–	-/-	-/-	–	–	–	-/-	-/-	–	–	–	–	–
RESIN SLURRY/ PRECOAT SLURRY (SEE NOTE 3)	RESIN SLURRY (FOR STEP 26, SEE NOTE 6)	FLOW (GPM)	360	180/180	180/180	180/180	180/180	180/180	0/0	0/0	0/0	0/0	0/0	0/0	0/0	25	0/0	0/0	0	0	0	0/0	0/0	0	0	0	0	25
		TEMPERATURE (F)	120	120/120	120/120	120/120	120/120	120/120	-/-	-/-	-/-	-/-	-/-	-/-	-/-	80	-/-	-/-	–	–	–	-/-	-/-	–	–	–	–	80
		PRESSURE (PSIG)	1150	1150	1139	1119	1107	1091	-/-	-/-	-/-	-/-	-/-	-/-	-/-	80	-/-	-/-	–	–	–	-/-	-/-	–	–	–	–	80
	PRECOAT SLURRY (FOR STEP 18, SEE NOTE 6)	FLOW (GPM)	360	180/180	180/180	180/180	180/180	180/180	0/0	0/0	0/0	0/0	0/0	0/0	0/0	40	0/0	0/0	0	40	0	0/0	0/0	0	0	0	0	0
		TEMPERATURE (F)	120	120/120	180/180	180/180	180/180	180/180	-/-	-/-	-/-	-/-	-/-	-/-	-/-	80	-/-	-/-	–	80	–	-/-	-/-	–	–	–	–	–
		PRESSURE (PSIG)	1150	1150	1139	1119	1107	1091	-/-	-/-	-/-	-/-	-/-	-/-	-/-	80	-/-	-/-	–	80	–	-/-	-/-	–	–	–	–	–

POINTS

MODE	SUB-MODE	PARAMETER	27	28	29	30
BACKWASH RECEIVING TANK PUMP DISCHARGE	RECIRC & DISCHARGE TO RADWASTE SYSTEM	FLOW (GPM)	200	200	140	60
		TEMPERATURE (F°)	120	120	120	120
		PRESSURE (PSIG)	0	43	40	43

NOTES:

1. SEQUENCE OF OPERATION
   - I. SERVICE
     - A. SERVICE (A & B)
   - II. HOLDING
     - A. ISOLATE & HOLD
   - III. BACKWASH
     - A. DEPRESSURIZE
     - B. DOME DRAIN
     - C. AIR PRESSURIZE
     - D. 1ST AIR BUMP & DRAIN
     - E. FILL & VENT
     - F. DOME DRAIN
     - G. AIR PRESSURIZE
     - H. 2ND AIR BUMP & DRAIN
     - I. BACKWASH & DRAIN
     - J. FILL & VENT
   - IV. FLOC PRECOAT
     - A. SOLKA-FLOC PRECOAT & RETURN
   - V. RESIN PRECOAT
     - A. RESIN PRECOAT & RETURN
   - VI. HOLDING
     - A. HOLD PRECOAT & RETURN
     - B. HOLD UNTIL RETURN TO SERVICE
   - VII. SERVICE
     - A. SERVICE - SAME AS "I".
2. ALL HOLDING, BACKWASHING, AND PRECOATING OPERATIONS ARE SHOWN FOR UNIT A WHILE UNIT B REMAINS IN NORMAL OPERATION. THIS IS TYPICAL FOR HOLDING, BACKWASHING, AND PRECOATING OPERATIONS OF UNIT B WHILE UNIT A IS IN NORMAL OPERATION.
3. RESIN AND PRECOAT SLURRY MAY TAKE PLACE AT ANY TIME WHILE BOTH UNITS ARE IN SERVICE.
4. THE DATA SHOWN ON THIS FLOW DIAGRAM ARE FOR DESIGN PURPOSES ONLY, AND WHILE USEFUL AS GUIDES IN OPERATION, DO NOT REPRESENT EXACT OR GUARANTEED OPERATING CONDITIONS.
5. FIRST AIR BUMP AND DRAIN FLUSHES 74 lbs OF SOLIDS (DRY WEIGHT) TO BACKWASH RECEIVING TANK. SECOND AIR BUMP AND DRAIN AND BACKWASH AND DRAIN STEPS FLUSH RESIDUAL SOLIDS TO BACKWASH RECEIVING TANK. RESIN SLURRY ADDS 34 lbs (DRY WEIGHT) TO RESIN PRECOAT TANK. PRECOAT SLURRY ADDS 34 lbs TO PRECOAT TANK.
6. NORMAL BACKWASH-PRECOAT FREQUENCY IN EACH VESSEL EVERY 6-14 DAYS.

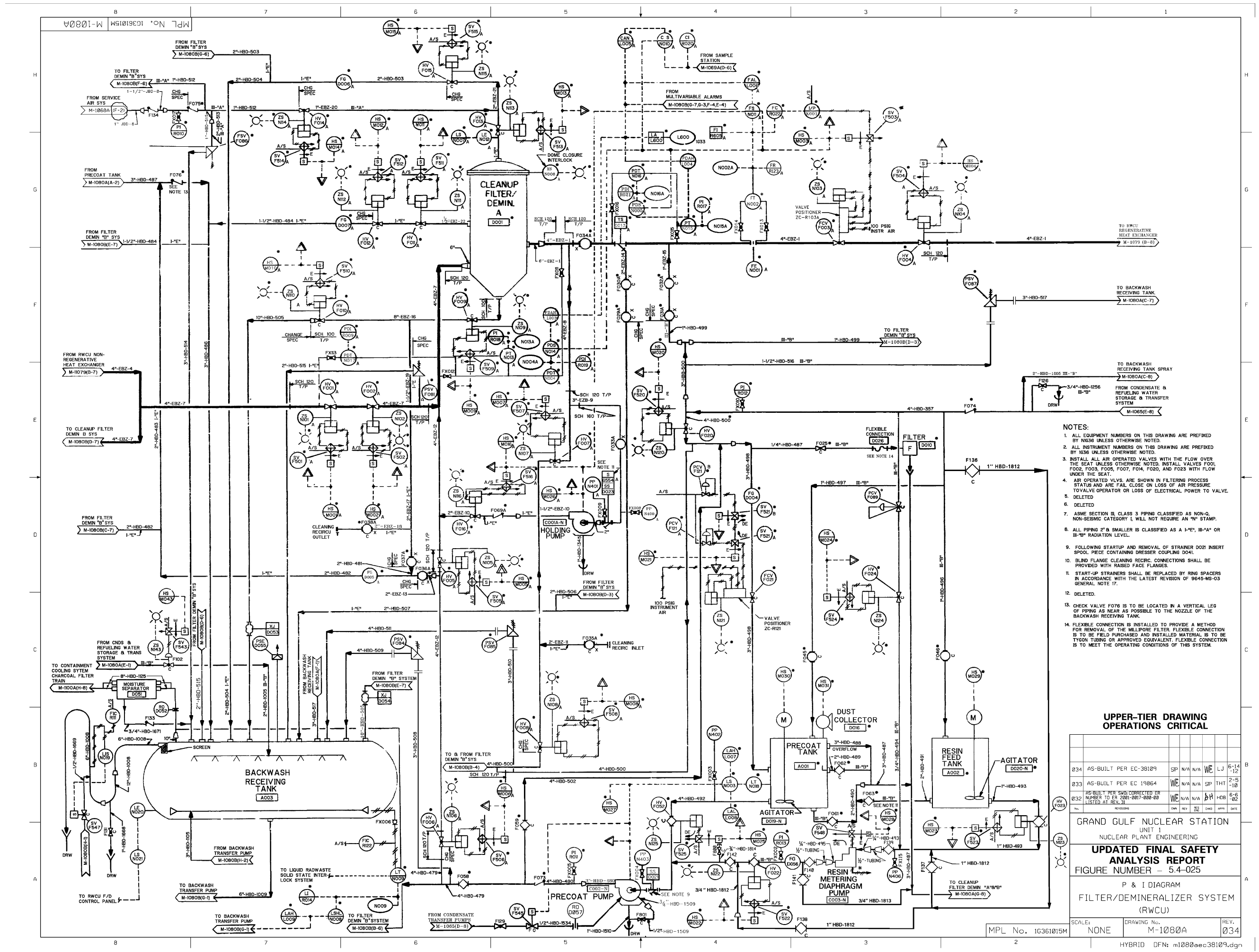
REV.	DATE	REVISION
1		INCORP DCN #1
0		ISSUED FOR CONSTRUCTION

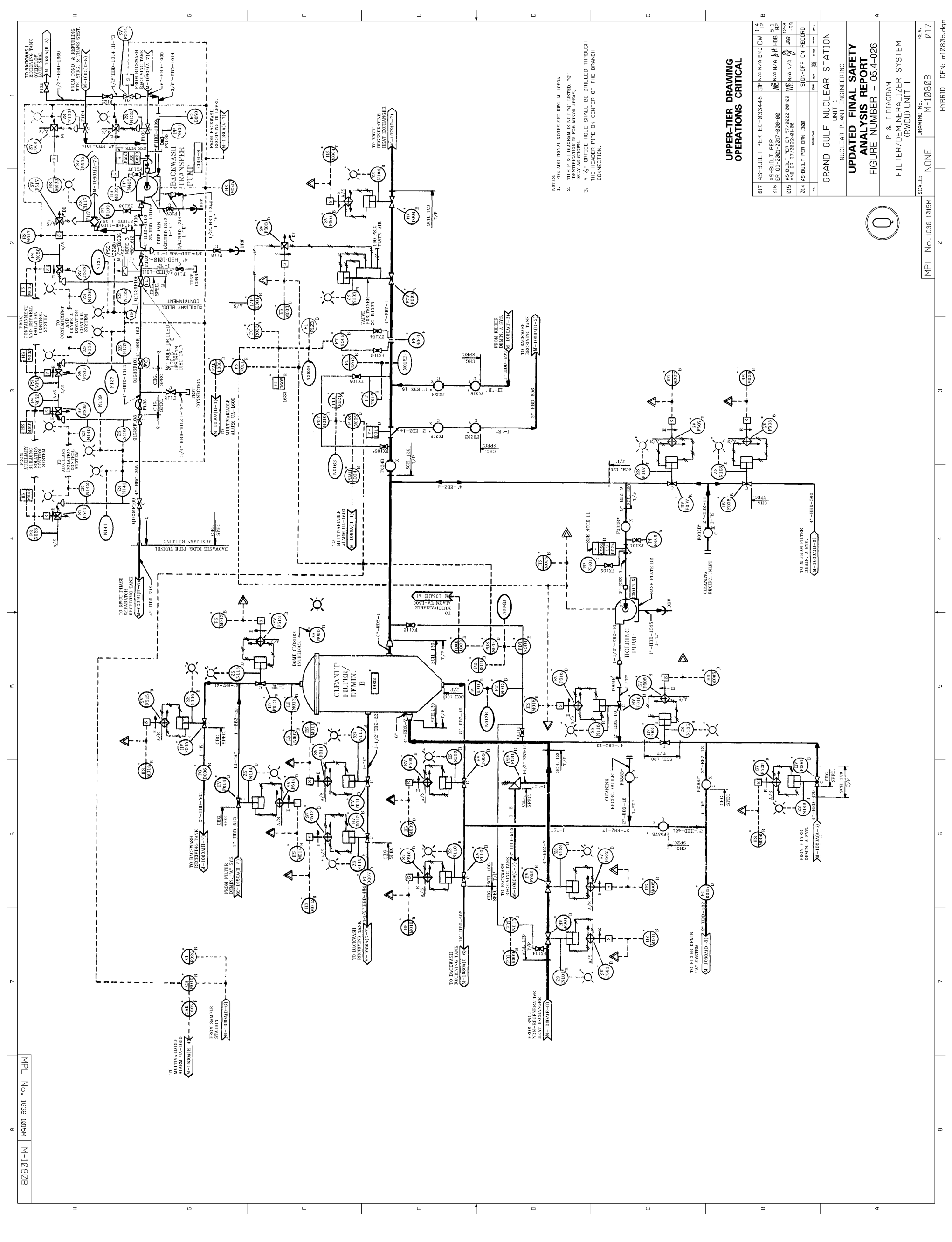
BECHTEL
GAITHERSBURG, MARYLAND

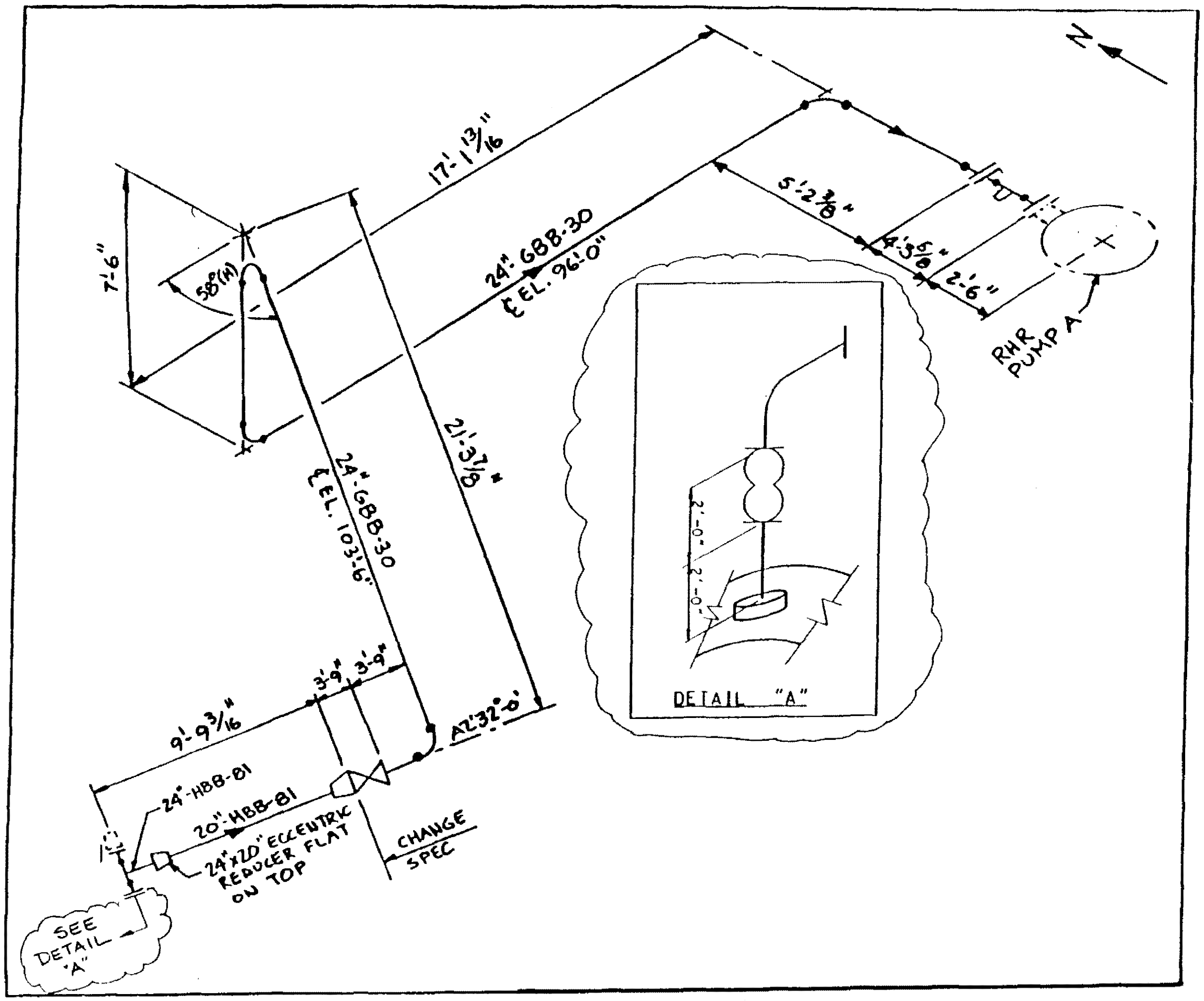
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2

SYSTEM FLOW DIAGRAM
R.W.C.U. FILTER/DEMINERALIZER SYSTEM
UNIT 1

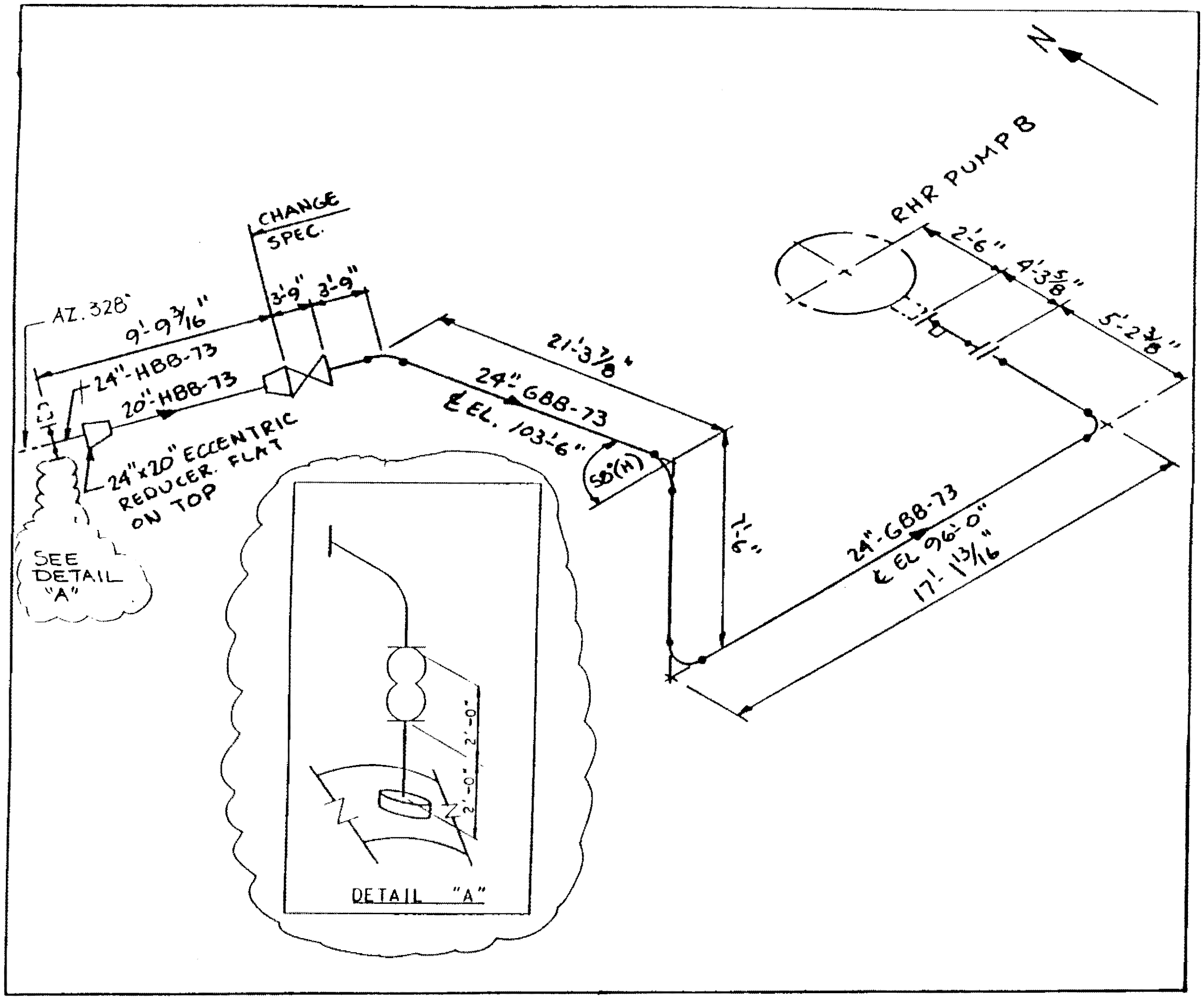
MPL No. 1G36 1025M — JOB No. 9645- — DRAWING No. SFD-1080 SH. 2 — REV. 1


CLEANUP FILTER/ DEMIN. A
BACKWASH RECEIVING TANK
HOLDING PUMP
PRECOAT PUMP
PRECOAT TANK
AGITATOR
RESIN METERING DIAPHRAGM PUMP
RESIN FEED TANK
DUST COLLECTOR
UPPER-TIER DRAWING OPERATIONS CRITICAL
GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER - 5.4-025
P & I DIAGRAM
FILTER/DEMINERALIZER SYSTEM
(RWCU)
MPL No. 1G361015M
M-1080A
034

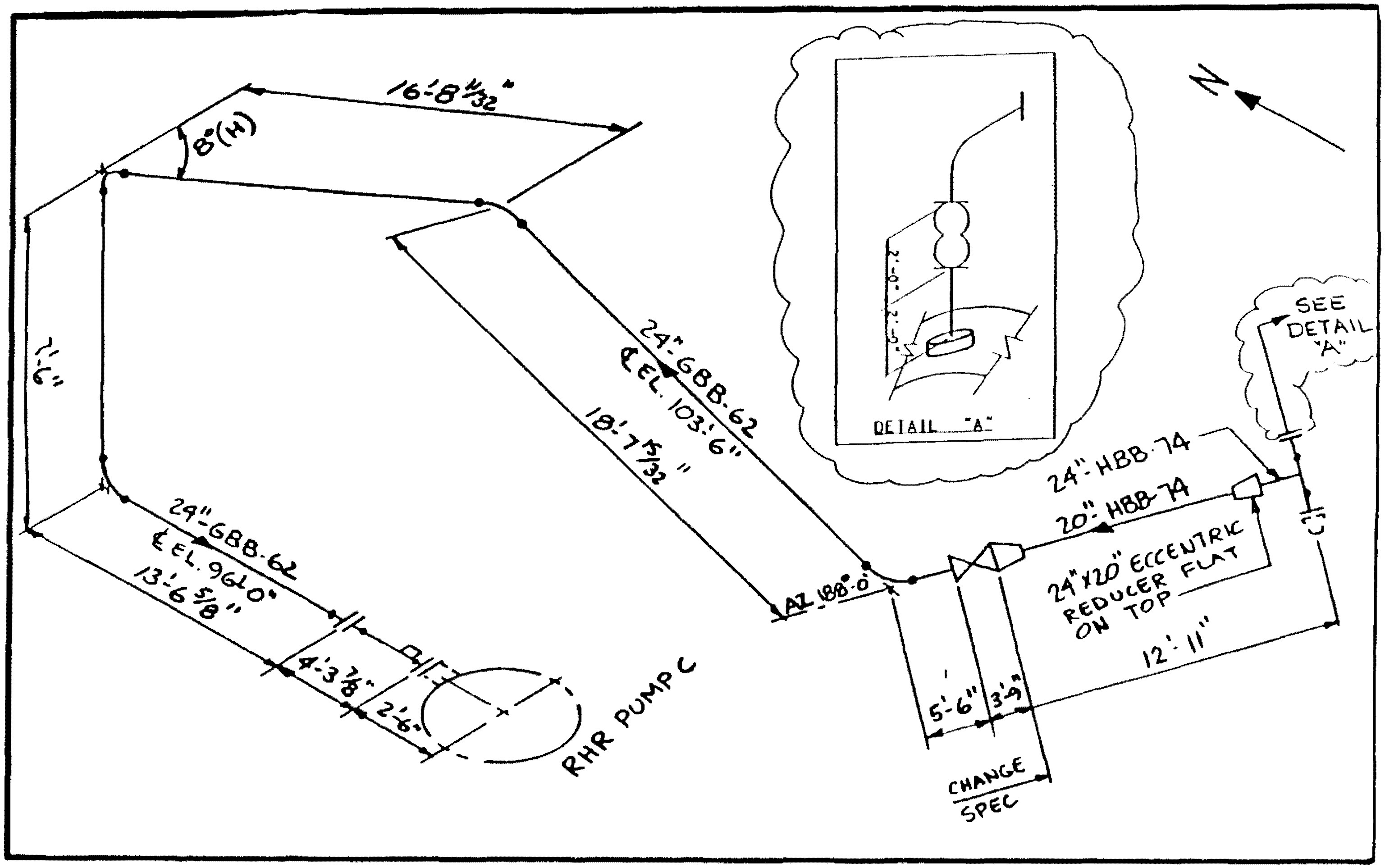

UPPER-TIER DRAWING
OPERATIONS CRITICAL
GRAND GULF NUCLEAR STATION
UNIT 1
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY
ANALYSIS REPORT
FIGURE NUMBER - 05.4-026
P & I DIAGRAM
FILTER/DEMINERALIZER SYSTEM
(RWCU) UNIT 1
CLEANUP FILTER/ DEMIN. D
BACKWASH TRANSFER PUMP
HOLDING PUMP
M-1080B



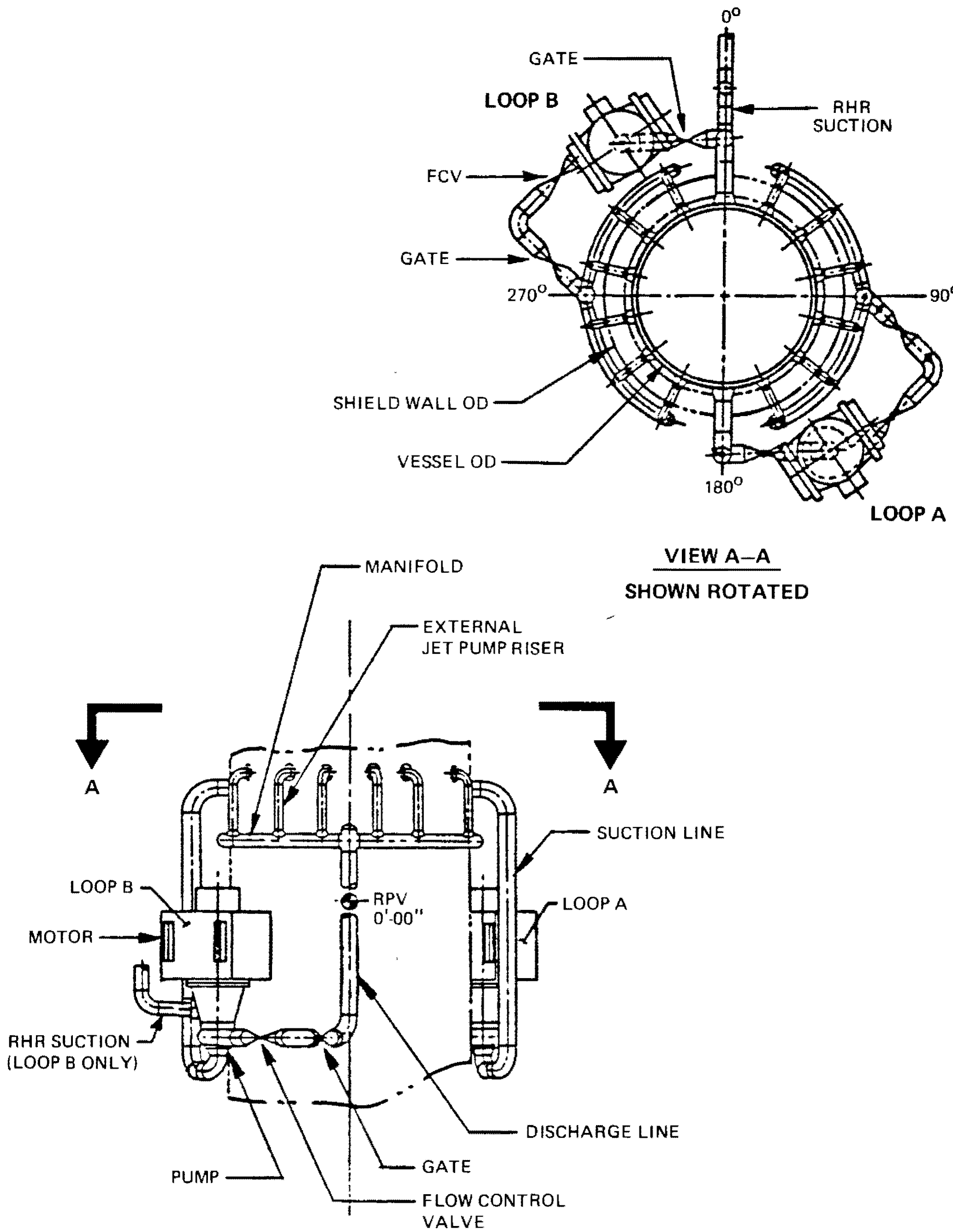
GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	RHR PUMP A SUCTION LINE ARRANGEMENT FIGURE 5.4-27



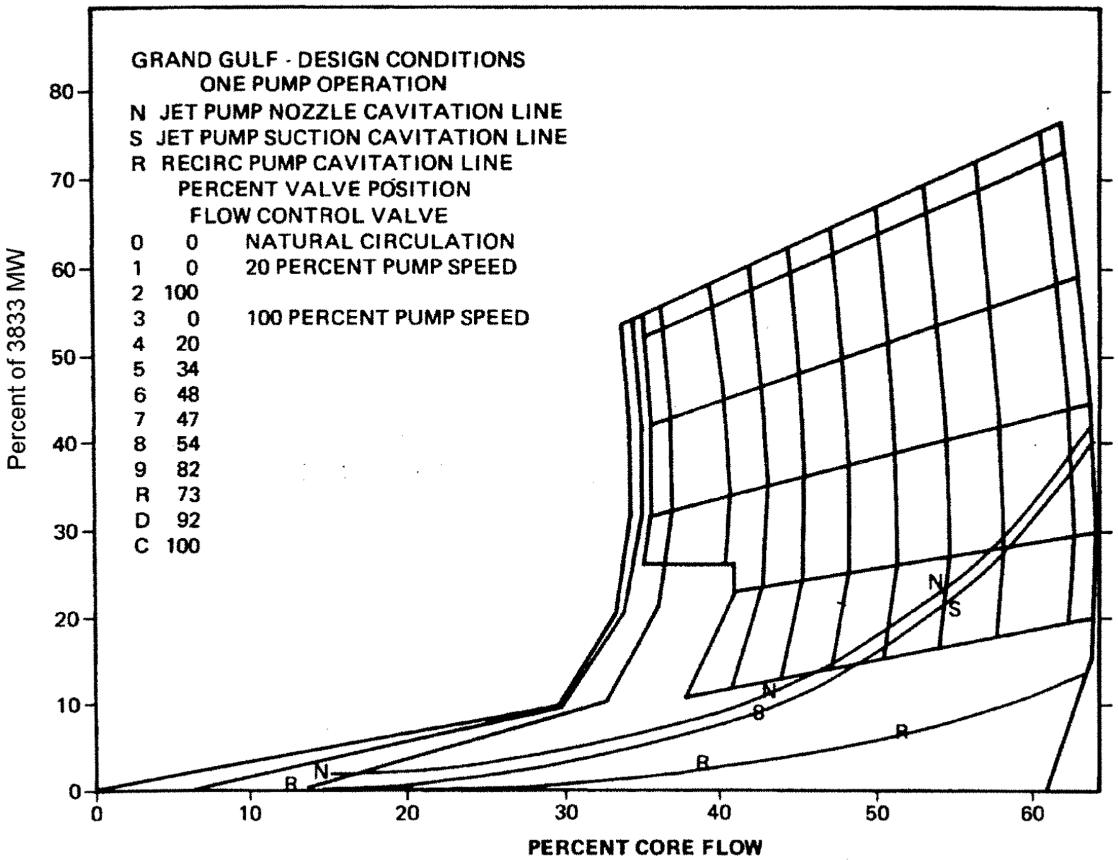
GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	RHR PUMP B SUCTION LINE ARRANGEMENT FIGURE 5.4-28



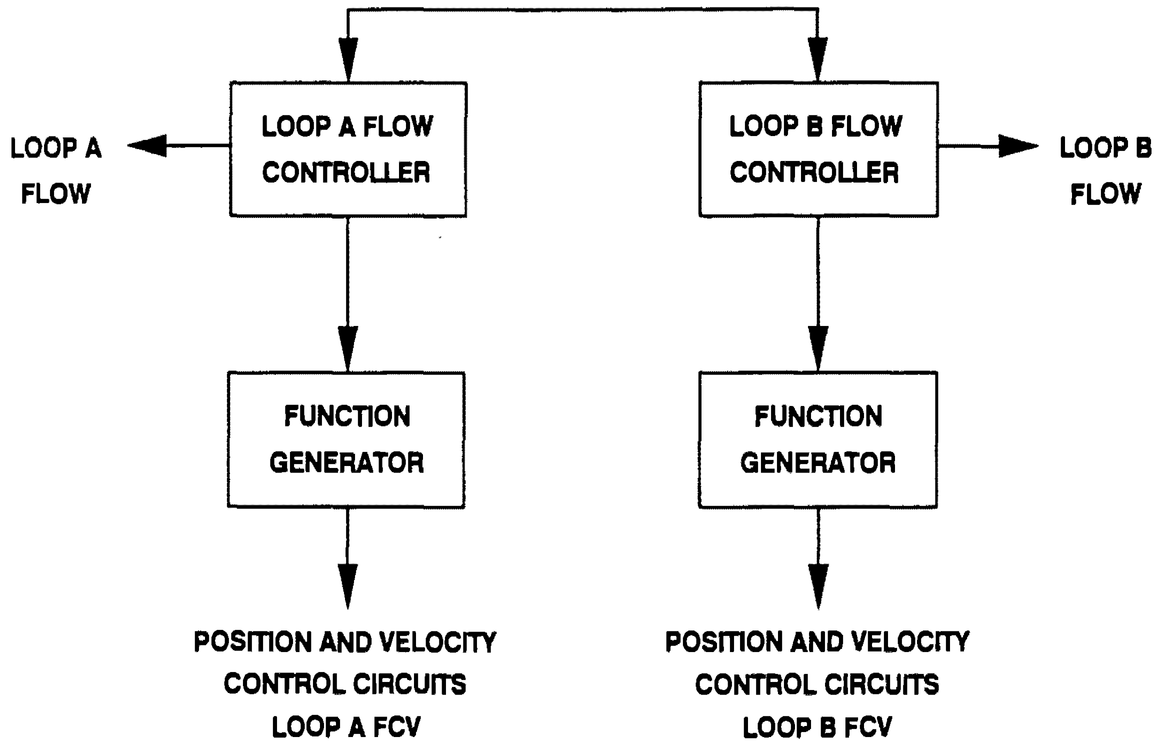
GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	RHR PUMP C SUCTION LINE ARRANGEMENT FIGURE 5.4-29



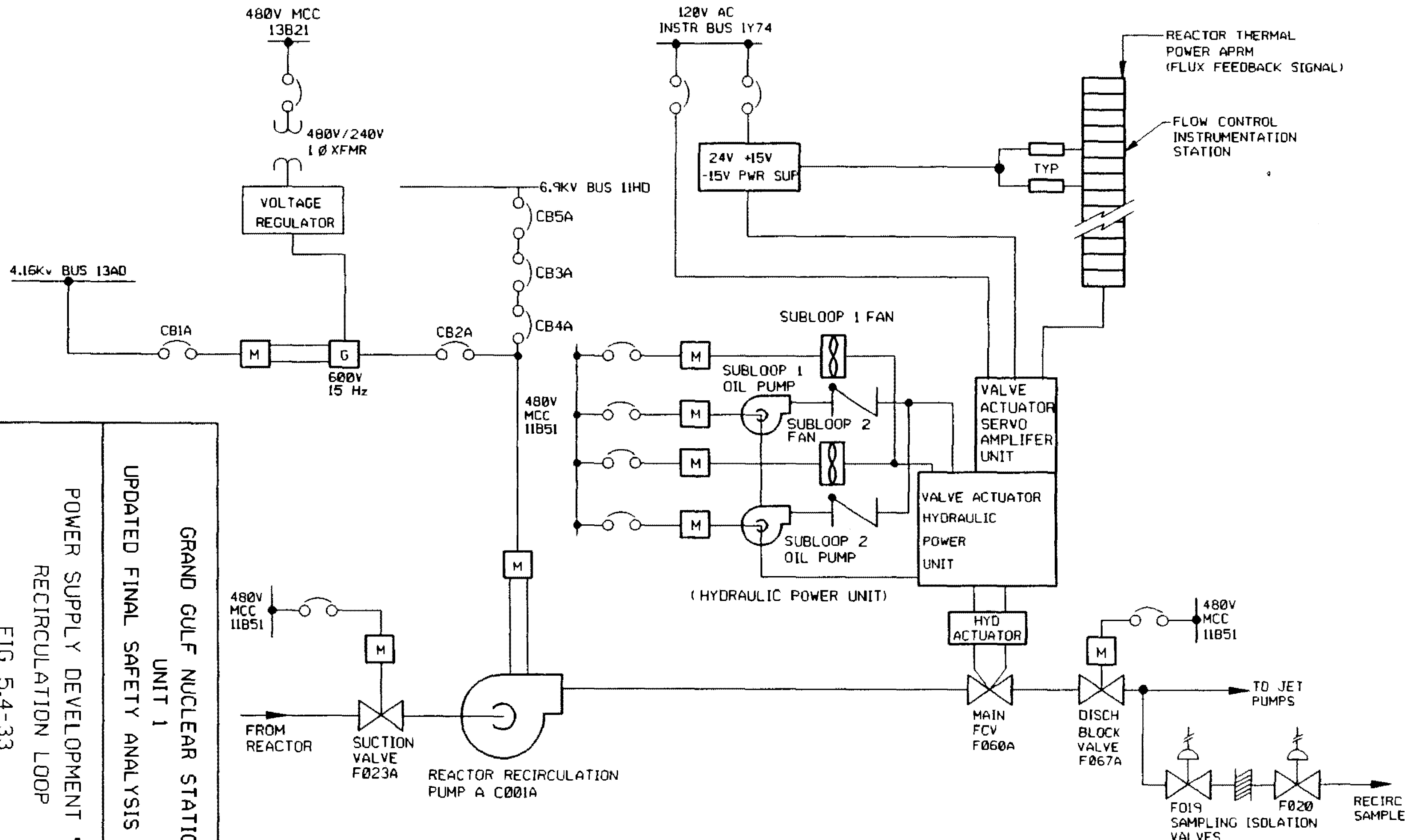
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	RECIRCULATION SYSTEM EXTERNAL LOOP PIPING LAYOUT FIGURE 5.4-30



GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	ONE PUMP OPERATION MAP FIGURE 5.4-31 [HISTORICAL INFORMATION]

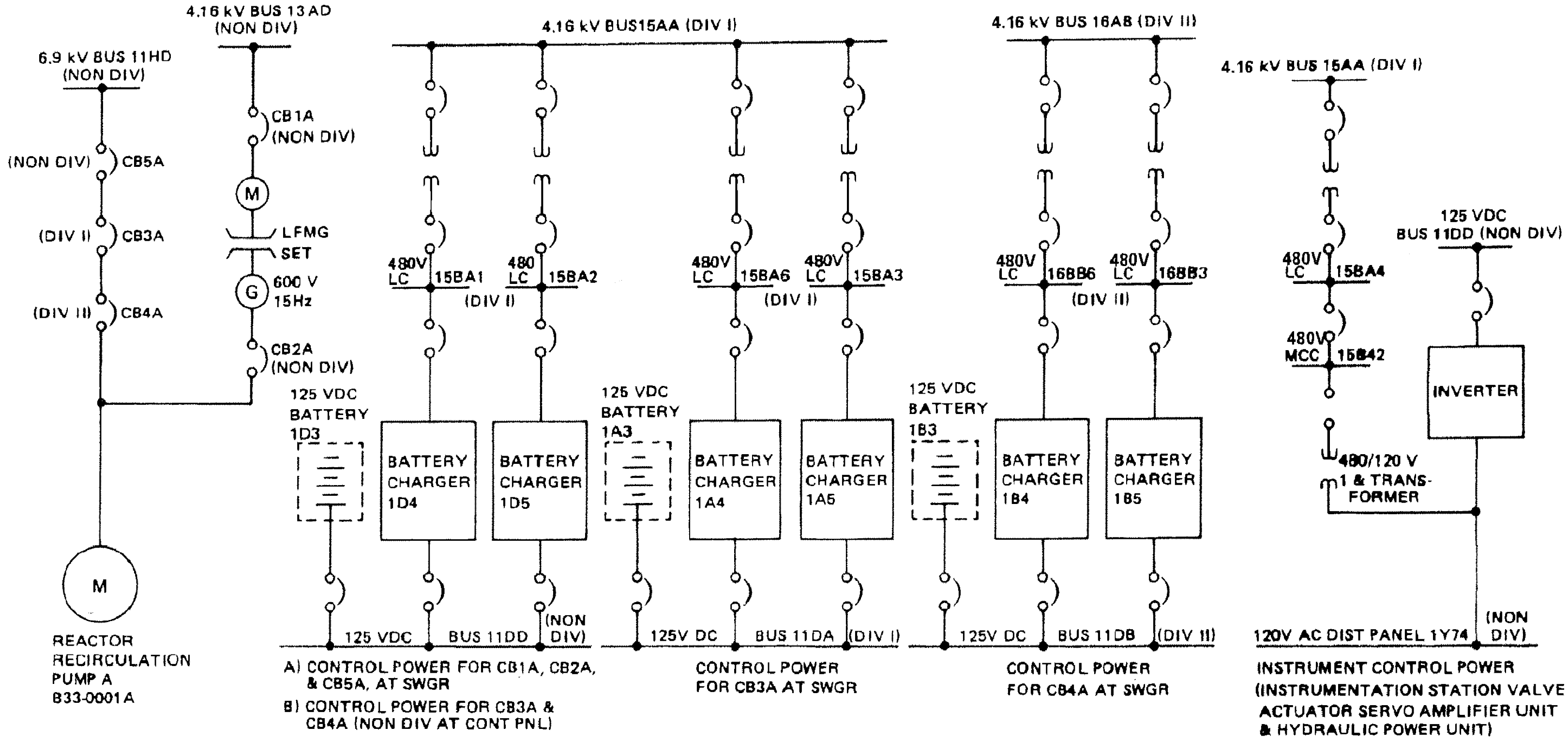


GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	RECIRCULATION FLOW CONTROL SYSTEM BLOCK DIAGRAM FIGURE 5.4-32

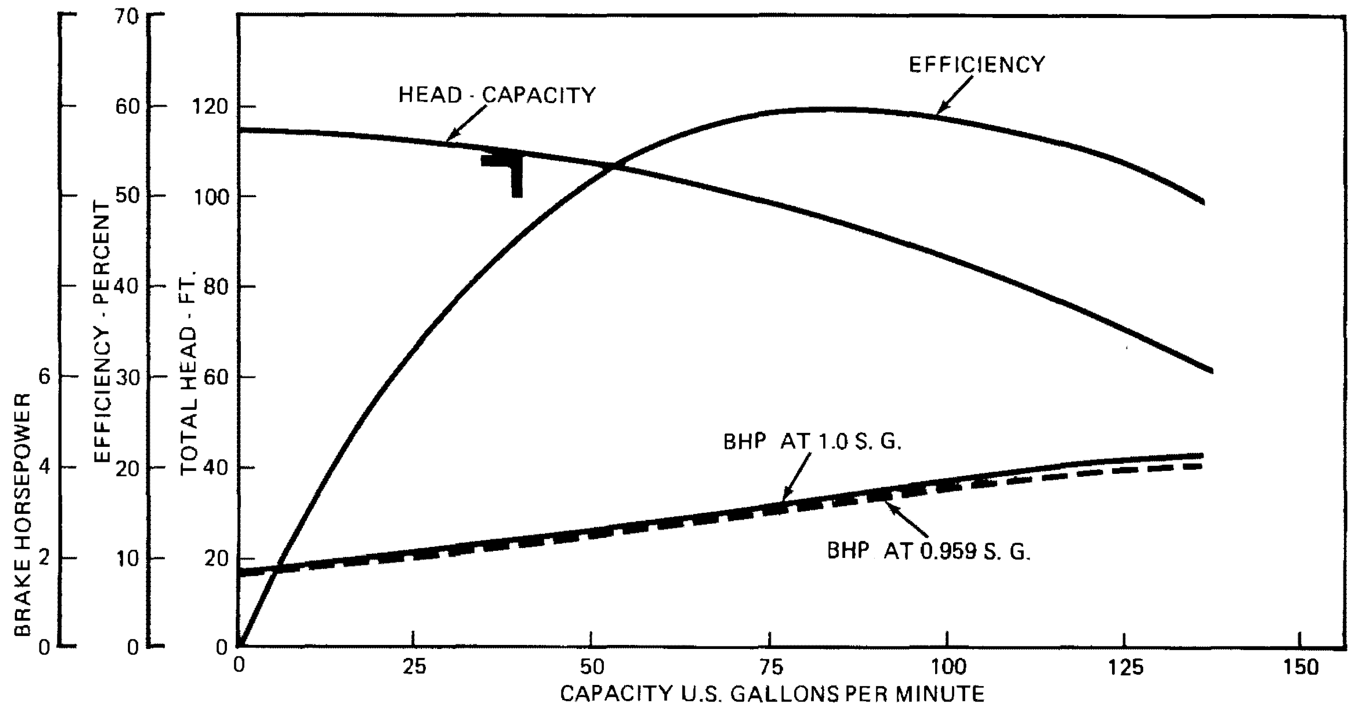


GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

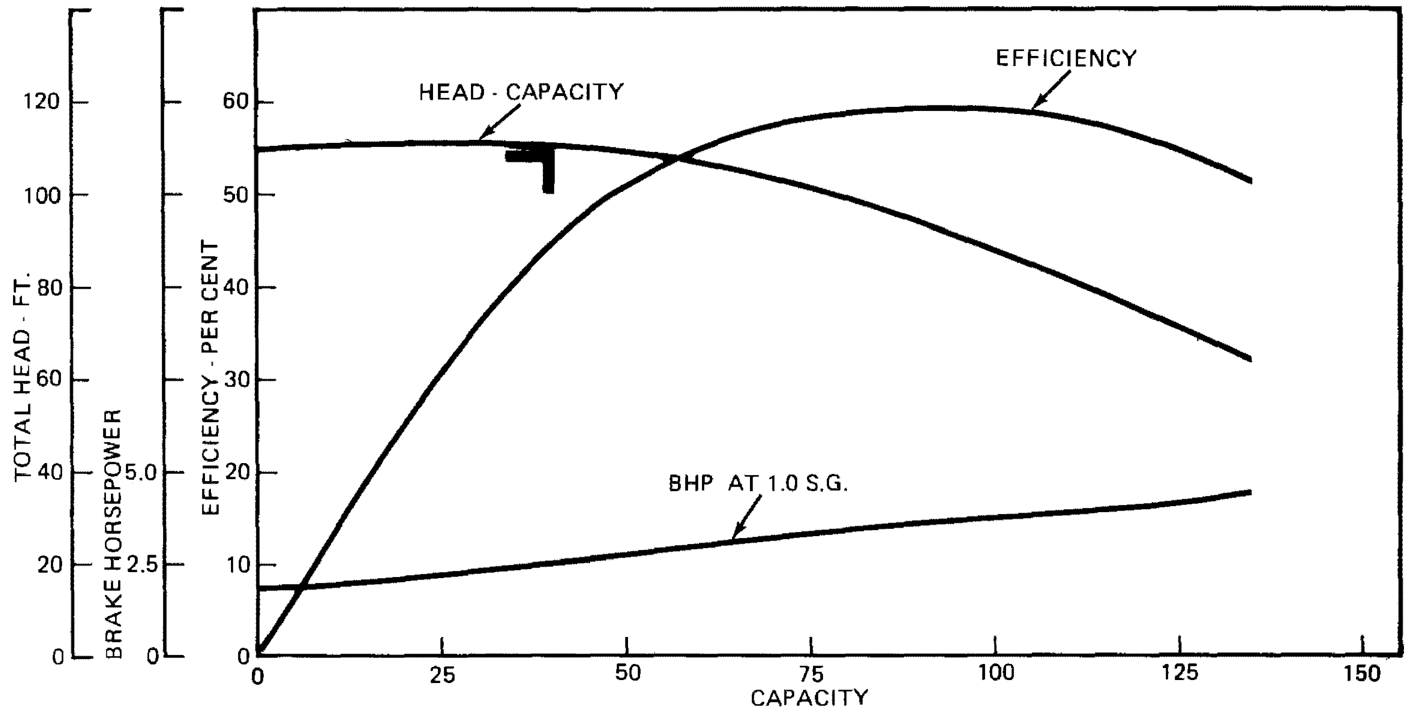
POWER SUPPLY DEVELOPMENT 'A'
RECIRCULATION LOOP
FIG 5.4-33



GRAND GULF NUCLEAR STATION UNITS 1 UPDATED FINAL SAFETY ANALYSIS REPORT	LAYOUT OF AUXILIARY POWER SYSTEM FOR REACTOR RECIRCULATION SYSTEM PUMP 'A' FIGURE 5.4-34



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	TYPICAL PERFORMANCE CURVES, RHR JOCKEY PUMPS FIGURE 5.4-35



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	TYPICAL PERFORMANCE CURVES, HPCS & LPCS JOCKEY PUMPS FIGURE 5.4-36

5.5 IDENTIFICATION OF ACTIVE PUMPS AND VALVES

5.5.1 Classification of Pumps and Valves

Pumps and valves within the reactor coolant pressure boundary are classified as active or inactive in Table 5.2-5.

Active components are those whose operability is relied on to perform a safety function during the transients or accidents.

Inactive components are those whose operability (e.g., valve opening or closure, pump operation or trip) is not relied on to perform the system's safety function during transients or accidents.

The isolation signals which activate the isolation valves are as described in subsection 7.3.1.1.2.4.1. The times for closed or open cycles are listed in Table 6.2-44.

Leaktightness capability requirements for all active valves shall be included in applicable valve specifications. Valve parts forming the pressure boundary shall be pressure tested per the requirements of the applicable code.

5.5.2 Pipe Break

The design criteria employed to assure that components will function as designed in the event of a pipe rupture is described in the following subsections:

5.5.2.1 Reactor Recirculation Pump and Motor

The term "active" requires that equipment must be designed to additional requirements in accordance with the applicable codes and standards (ASME, IEEE, Quality Assurance, etc). It is not desirable to classify those components having a safety function as "active" when the additional requirements do not provide increased expectation that the safety function will be performed. Because the recirculation pump is part of the RCPB and is designed to ASME Code, Section III, Class 1, the additional requirements imposed by the term "active" do not decrease the probability that the pump will seize. For instance, the recirculation pump and/or recirculation motor are example of components whose operability* is not required for safety but is merely required not to instantaneously fail (seize). The additional requirements imposed by the term "active" would not increase the reliability of the system to perform its safety function (coastdown). As such, the recirculation pump and motor are classified as "inactive" (Table 5.2-5). Further,

* Components may continue to operate or may trip off and coast down; either mode is acceptable.

in order to assure the functional performance of the recirculation pump and motor, the following additional requirements are specified:

a. The LOCA shall not degrade coastdown performance in the unbroken loop to the extent that the core is deprived of adequate cooling.

b. The pump and motor bearings shall have sufficient dynamic load capability at rated operating conditions to withstand the safe shutdown earthquake.

GE topical report NEDO-24083 discusses the loss of cooling water to the recirculation pumps.

5.5.2.2 Recirculation Flow Control Valve

The flow control valve is classified as inactive (Table 5.2-5). The system is designed to prevent rapid closure of the valve during the LOCA so that the valve does not decrease the pump flow rate in the unbroken loop.

5.5.2.3 Recirculation Suction Blocking Valve

a. The valve in the unbroken loop is capable of remote manual closure from the control room.

b. The maximum permissible seal leak rate is conservatively estimated to be 5 gpm.

c. The valve closure time is 2 minutes ± 10 percent.

5.5.2.4 Safety/Relief Valves

It is not required that the safety/relief valves operate during a LOCA pipe rupture.

5.5.2.5 Isolation Valves

a. All power-operated isolation valves are capable of closing at any time during normal, abnormal, or test conditions. During accident conditions, adequate isolation exists to ensure site boundary limits are not exceeded.

b. Valves required for emergency cooling systems shall remain operable, for both opening or closing as required for system functions, after an accident.

c. Valve operation shall be controlled by the signals described in subsection 7.3.1.1.2.4.1 and in Table 6.2-44.

5.5.2.6 Pipe Rupture Dynamic Effects

Protection against dynamic effects of pipe rupture is described in Section 3.6.

5.5.3 Design of Active Pumps and Valves

[HISTORICAL INFORMATION] [In order to assure the functional performance of active valves of the RCPB, stringent design requirements were applied. Valve operability was demonstrated by the following paragraphs.

All active valves are being qualified for operability assurance by first being subjected to the following tests:

a. Shop tests which include hydrostatic texts and seal leakage tests as specified in the applicable Code

b. The valves were required to open and close within specified time limits when subjected to design or environmental conditions as required by applicable codes and regulatory guides. Vibrational levels will also be monitored when required. There are also other tests, such as the cold hydro and hot functional tests, to b e performed on site. Valves are considered to be rigid under seismic disturbances. Thus conservative seismic accelerations of 1.5g horizontal and .14g vertical were used simultaneously in the structural analyses.

With the loads known from above, the structural analysis was performed with other conservative loads to meet the stress criteria. This will assure that the critical parts of the concerned component will not be damaged during and after the faulted condition.

Finally, active valves are also required to be operated periodically. This repeated operability requirement throughout the life of the specified valve further provides a complete operability assurance program.

RCPB Class 1 active valves are included in Table 5.2-5. A description of NSSS ASME Code, Section III, Class 1, 2, and 3 active pumps and valves is given in Section 3.9.3.2.

The representative combination of loads and analysis to assure operability are summarized in Table 3.9.2.]

5.5.4 Inadvertent Operation of Valves

A discussion of the design basis events and their appropriate limits for this plant is given in Chapter 15. The events in Chapter 15 have been selected to envelope the most severe change in critical parameters from events which have been postulated to occur during planned operation.

5.5.5 Analytical Methods for Evaluation of Pump Seed and Bearing Integrity

[HISTORICAL INFORMATION] [Tests and procedures used to evaluate critical speed problems in pumps and to assure the integrity of the bearings for the transient conditions are briefly discussed in the following subsections.

5.5.5.1 Pump Shaft Critical Speed

The first critical speed of the recirculation pump shaft has been calculated to be above 130 percent of the operating speed. The absence of shaft vibration has been verified by testing the pump under rated speed conditions. The absence of vibration will be further verified in the plant during preoperational testing.

5.5.5.2 Pump Bearing Integrity

Adequacy of the bearing design has been verified by full temperature and pressure tests.]

5.5.6 Operation of Active Valves Under Transient Loadings

[HISTORICAL INFORMATION] [The qualification test program used to verify that active valves (whose operability is relied upon to perform a safety function or shut down the reactor) within the RCPB will operate under the transient loadings experienced during service life is described int he following subsections.

5.5.6.1 Main Steam Line Isolation Valves

Components of the MSIV, which are required to operate during transient conditions, whose functional capabilities are sensitive to the abnormal ambient pressure and temperature associated with the transient, are subjected to a test sequence which simulates the abnormal ambient condition. Functional requirements are verified throughout the test sequence. Components tested are fully representative of production components.

5.5.6.2 Safety/Relief Valves

The safety/relief valves are subjected to tests that simulate conditions experienced during service life.

5.5.6.3 Other Provisions to Assure Operability

Valves in the reactor coolant pressure boundary have been tested in accordance with the applicable codes. Thermal transient loadings on pressure boundary valves will not be simulated.

To assure operability of active valves under the transient loadings to be experienced during plant service life, Design Specifications include the following requirements:

a. Valve bodies and yoke structures have been designed to withstand seismic forces.

b. Valve operators have been sized to open or close under the maximum differential pressure across the valve seat, dictated by the transient service conditions.

c. Valves have been fully cycled at the vendor's shop before delivery to substantiate the vendor's guarantee that they will operate under actual service pressure conditions.

d. All motor-operated valves have been equipped with handwheels so that motors can be declutched and valves cycled manually after installation.]

APPENDIX 5A DELETED