GE Nuclear Energy

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U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Attention: Robert C. Pierson, Director
Standardization and Non-Power Reactor Project Directorate

Subject: Tier I Design Certification Material for the GE ABWR Design
Stage 3 Submittal

Enclosed are thirty-four (34) copies of the Stage 3 GE ABWR Tier I Design Certification material. This Stage 3 material includes the following:

- Design descriptions and proposed inspections, tests, analyses and acceptance criteria (ITAAC) for all of the ABWR systems for which design certification is being sought.

- Tier I entries for generic issues such as equipment qualification and radiation protection. This generic material includes technical issues for which certification will be based on approval of design acceptance criteria (DAC).

- Interface requirements and associated ITAAC as called for by 10 CFR Part 52 for those portions of the plant for which design certification is not being sought.

- A definition of the site-related parameters which have been used as input to the ABWR design process.

This submittal represents fulfillment of the GE commitment to submit Stage 3 Tier 1 material by the end of May 1992.

The enclosed material does not include the following information:

1. Comprehensive responses to ITAAC-related NRC comments received by GE in the last few weeks.

2. Tier I material for the Human Factors Engineering (HFE)/main control room design process. This issue is being actively reviewed by GE-NRC and by mutual agreement is not addressed in the enclosed Stage 3 submittal. The HFE material will be added to the attached Tier I document when a mutually acceptable version is in place.

3. Any proposed road map material beyond that presented in the Stage 2 submittal. GE believes there is an understanding that preparation of road maps is an after-the-fact exercise which can best be undertaken following resolution of NRC comments on the Tier I material.

GE views the enclosed document as draft in the sense that we fully anticipate technical interactions with the staff and modifications of the enclosed material similar to the process which has occurred on earlier Tier I submittals. GE believes mutually acceptable schedules should now be established for NRC comments/GE responses on the entire Tier 1 package. We believe this schedule discussion should be an agenda item for the upcoming June 8 GE/NRC management meeting in San Jose.

Sincerely,

PWMarriott

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1.0 Introduction

GE has applied for design certification of the Advanced Boiling Water Reactor (ABWR) design under the provisions of 10CFT Part 52. As endorsed by the NRC commissioners, the design certification process is proceeding on the basis of a tiered approach. Tier 1 will be the certified Rule and will include a description of the principal design bases and principal features of the certified design. More specifically, Tier 1 will include:

(1) A design description together with inspections, tests, analyses and acceptance criteria (ITAAC) entries for each of the approximately 100 systems in the ABWR facility for which design certification is being sought.

(2) Tier 1 entries for selected generic issues such as equipment qualification(EQ) and radiation protection. This generic material includes technical issues for which certification will be based on approval of design acceptance criteria (DAC).

(3) Interface requirements and the associated ITAAC as called for by 10CFR Part 52 for those portions of the plant for which design certification is not being sought.

(4) A definition of the site-related parameters which have been used as input to the ABWR design process. These site-related design parameters have been selected with the intent they envelope conditions at most potential sites in the United States.

The purpose of this report is to present the Tier 1 material for the ABWR.

Tier 2 will encompass the larger body of design material submitted as part of the certification application . • documented in the plant Safety Analysis Report (SAR). Tier 2 material is not addressed in this report.

This document is structured as follows:

Section 1.1—A top-level General Plant Description intended to be a Tier 1 design description entry. This material provides a broad overview of the plant and addresses general features and characteristics not covered by the more detailed system material which forms the bulk of the Tier 1 design descriptions. Examples of issues addressed in Section 1.1 are the site plot plan, facility thermal and electrical power output, and major plant thermal-hydraulic parameters. No ITAAC are proposed for the technical entries in Section 1.1.

Section 2—A design description together with ITAAC entries for each of the approximately 100 systems within the scope of the ABWR design for which design certification is being sought.

Section 3—Tier 1entries that fall into the category of generic. This type of entry addresses technical issues that span multiple ABWR systems and is most appropriately handled in a single Tier 1 location. Section 3 includes a matrix showing which generic entries apply to each of the ABWR systems. In selected areas of the plant for which design details are (for legitimate reasons) unavailable, Design Acceptance Criteria (DAC) are being prepared. The DAC approach involves certification of the design process and is being applied to areas of the plant design for which design details are not available at the time of design certification. Section 3 includes Tier 1 material that is in this category.

Section 4—10 CFR Part 52 requires that the ITAAC include methods for verifying interface requirements. The latter are defined in 10 CFR Part 52 as the technical requirements to be met by those portions of the plant for which design certification is not being sought. Section 4 contains ITAAC entries required for compliance with this provision.

Section 5—Design of the ABWR requires quantified values of many site-related characteristics such as tornado strength, flood height, and earthquake accelerations. Since it is intended the certified ABWR design be referenceable for a wide range of sites, it has been necessary to specify a set of site design parameters enveloping the conditions which will occur at most potential power plant sites in the United States. Section 5 defines this envelope of site conditions. It is intended that any facility which references the certified design will utilize a site where the actual site-specific conditions are within the defined envelope.

Appendix A—A legend which defines the symbols used to prepare simplified figures of systems presented in Section 2.

Appendix B—GE is preparing indices which will be used to identify the relationship between Tier 2 (the SAR) entries and the Tier 1 ITAAC material. The intent of this index material is to provide a "road map" which will indicate which ITAAC entries are being used to verify key parameters defined in the SAR.

1.1 General Plant Description

The following is a summary of the Advanced Boiling Water Reactor (ABWR) Standard Plant principal design features and principal design criteria.

ABWR Standard Plant Scope

The ABWR Standard Plant includes all buildings which are dedicated exclusively or primarily to housing systems and the equipment related to the nuclear system or controls access to this equipment and systems. There are five such buildings within the scope of the ABWR Standard Plant:

(1) Reactor Building (including containment)

(2) Service Building

(3) Control Building

(4) Turbine Building

(5) Radwaste Building

In addition to the buildings and their contents, the ABWR Standard Plant provides the supporting facilities shown in Figure 1.1.

The principal plant structures include the following:

(1) Reactor Building—includes the containment, drywell, and major portions of the Nuclear Steam Supply System (NSSS), steam tunnel, refueling area, diesel generators, essential power, non-essential power, Emergency Core Cooling Systems (ECCS), Heating, Ventilation and Air Conditioning System (HVAC), and supporting systems.

(2) Service Building—personnel facilities, and portions of the non-essential HVAC.

(3) Control Building—includes the control room, the computer facility, the cable tunnels, some of the plant essential switchgear, some of the essential power, reactor building water system and the essential HVAC System.

(4) Turbine Building—houses all equipment associated with the main turbine generator. Other auxiliary equipment is also located in this building.

(5) Radwaste Building—houses all equipment associated with the collection and processing of solid and liquid radioactive waste generated by the plant.

Number of Plant Units

For the purpose of this design certification, a single standard plant is described.

Type of Nuclear Steam Supply

This plant will have a boiling water reactor (BWR) nuclear steam supply system (NSSS) designed by GE and designated as the Advanced Boiling Water Reactor (ABWR).

Type of Containment

The ABWR will have a low-leakage containment vessel comprised of the drywell and pressure suppression chamber. The containment vessel is a cylindrical steel-lined reinforced concrete structure integrated with the Reactor Building.

Core Thermal Power Levels

The information presented in this design certification pertains to one reactor unit with a rated power level of 3926 MWt and a design power level of 4005 MWt. The station utilizes a single-cycle, forced-circulation BWR designed to operate at a gross electrical power output of approximately 1356 MWe and an electrical power output of approximately 1300 MWe.

Principal Design Parameters

Rated power (MWt)	3,926
Design power (MWt) (ECCS design basis)	4,005
Rated steam flow rate, Kg/hr at 215.6°C (FW temp)	$7.64x10^6$
Rated core coolant flow rate (Kg/hr)	$52.2x10^6$
RCPB design pressure (Kg/cm^2g)	87.9
RCPB design temperature (°C)	302
Containment internal design pressure (Kg/cm^2g)	3.16
Number of fuel assemblies	872
Number of control rods	205
Number of internal pumps	10

2.0 Tier 1 Material for ABWR Systems

This section provides Tier 1 material for each of the ABWR systems within the scope of the certified design. The listing of systems to be addressed in Tier 1 is devired from and compatible with, the ABWR systems indentified in Table 3.2-1 of the plant Safety Analysis Report. In most cases, each system has (as a minimum) a Tier 1 design description which is intended to be the technical description of the facility that will appear in Tier 1 of the Certification Rule. Most systems also have entries defining the inspections, tests, analyses and acceptance criteria (ITAAC) called for by 10 CFR Part 52.

Notice

For a number of ABWR systems addressed in this document, the Tier 1 design description is accompanied by a schematic diagram of the system configuration. The diagrams include simplified system piping and instrumentation diagrams for hydraulic/pneumatic systems; simplified one-line diagrams for electrical systems; and simplified outline drawings for selected equipment items.

These diagrams are for the purpose of illustrating the principal design features of the ABWR systems and their relationship to each other. The simplified figures are not to scale and are not intended to be exact representations of the detailed system configurations that will be utilized in any facility referencing the certified design.

The proposed ABWR Tier 1 material includes numerical information for aspects of the design such as equipment performance, material compositions, structural dimensions and system configurations. Where appropriate, this numerical information includes the allowable range and/or tolerances. In those cases where allowable variations are not specifically quantified, the stated value should be considered nominal with tolerances based on accepted industry practices as they apply to the parameter being considered.

2.1 Nuclear Steam Supply

2.1.1 Reactor Pressure Vessel System

Design Description

The Reactor Pressure Vessel (RPV) System consists of (1) the reactor pressure vessel and its appurtenances, supports and insulation, and (2) the reactor internals enclosed by the vessel, excluding the core, in-core nuclear instrumentation, reactor internal pumps, and control rod drives.

The reactor coolant pressure boundary (RCPB) portion of the RPV System retains integrity as a radioactive material barrier during normal operation and following abnormal operational transients and design basis accidents (DBAs).

Certain RPV internals support the core, flood the core during a DBA, and support instrumentation utilized during a DBA. Other RPV internals direct coolant flow, separate steam, hold material surveillance specimens, and support instrumentation utilized for normal operation.

The RPV System provides guidance and support for the control rod drives (CRDs). It also admits and distributes the sodium pentaborate from the Standby Liquid Control (SLC) System.

The RPV System restrains the CRD in order to prevent the ejection of the control rod connected with the CRD in the event of a postulated failure of the RCPB associated with the CRD housing. A restraint is also provided for the reactor internal pump (RIP) in order to prevent it from becoming a missile in case of a postulated failure of the RCPB associated with the reactor internal pump.

The major plant design parameters are listed in Section 1.1. The configuration of the RPV System is shown on Figure 2.1.1a, with key dimensions presented in Table 2.1.1b, and the acceptable variations in these dimensions in Table 2.1.1c. The RPVS parameters (postulated break areas) used in LOCA analyses are identified in Table 2.1.1d.

Reactor Pressure Vessel, Appurtenances, Supports and Insulation

The reactor pressure vessel (RPV), as shown schematically in Figure 2.1.1a, consists of a vertical, cylindrical pressure vessel of welded construction, removable top head and head closure bolting and seals. The vessel includes the cylindrical shell, flange, bottom head, reactor internal pump (RIP) casings, penetrations, brackets, nozzles, venturi shaped flow restrictors in the steam outlet nozzles, and the shroud support, which includes the pump deck forming the partition between the RIP suction and discharge. The shroud support is an assembly consisting of a short vertical cylindrical shell, a horizontal annular pump deck plate and vertical stilt legs. This support carries the weight of peripheral fuel assemblies, neutron sources, core pla , top guide, shroud, and shroud head with steam separators. It also laterally supports the fuel assemblies and the pump diffusers. The shroud support also sustains the differential pressures.

The control rod drives (CRDs) are mounted into the CRD housings. Sodium pentaborate solution from the SLC System enters the vessel via one of the two high pressure core flooding (HPCF) lines a d is distributed through the sparger connected to the line.

The CRD housings are inserted through and connected to the CRD penetrations (stub tubes) in the reactor vessel bottom head. The in-core neutron flux monitor housings are inserted through and connected to the bottom head.

A flanged nozzle is provided in the top head for bolting of the flange associated with the instrumentation for vibration test of internals.

The integral reactor vessel skirt supports the vessel on the RPV pedestal. Steel anchor bolts extend through the pedestal and secure the flange of the skirt to the pedestal. RPV stabilizers are provided in the upper portion of the RPV to resist horizontal loads. Lateral supports among the CRD housings and in-core housings are provided by restraints which, at the periphery, are supported off the CRD housing restraint beams.

A restraint consisting of a pair of energy absorbing rods is provided to prevent a RIP from being a missile in case of a failure in the casing weld with the bottom head penetration. The restraint is connected to lugs on the RPV bottom head and the RIP motor cover.

The RPV insulation is supported from the biological shield wall surrounding the vessel. Insulation for the upper head and flange is supported by a steel frame independent of the vessel and piping. Insulation access panels and insulation around penetrations are designed for ease of installation and removal for vessel inservice inspection and maintenance operation.

The RCPB portion of the RPV and appurtenances and the supports (RPV skirt, stabilizer and CRD housing/in-core housing restraints and beams) are classified as Quality Group A, Seismic Category I. The design, materials, manufacturing, fabrication, testing, examination, and inspection used in the construction of these components meet the requirements of ASME Code Class 1 vessel and supports, respectively. The shroud support is classified as Quality Group C, Seismic Category I, and designed and fabricated to ASME Code Class CS (core support structures). Hydrostatic test of the RPV is performed in accordance with the requirements for ASME Code Class 1 vessels. The components are code-stamped according to their code class.

The materials used in the RCPB portion of the RPV and appurtenances (or their equivalents) will be used: ASME SA-533, Type B, Class 1 (plate); SA-508, Class 3 (forging); SA-508, Class 1 (forging); SB-166, Type 600 (UNS 06600, forging); SA-182, F316L (maximum carbon 0.020%) or F316 (maximum carbon 0.020% and nitrogen from 0.060 to 0.120%, forging); and SA-540, Grade B23 or B24 (bolting).

The materials of the low alloy plates and forging used in construction of the RPV are melted to fine grain practice and are supplied in quenched and tempered condition. Vacuum degassing is performed to lower the hydrogen level and improve the cleanliness of the low-alloy steels.

Electroslag welding is not applied for structural welds. Preheat and interpass temperatures employed for welding of low alloy steel meet or exceed the values given in ASME, Section III, Appendix D. Post-weld heat treatment at 593°C minimum is applied to all low-alloy steel welds.

Pressure boundary welds are given an ultrasonic examination in addition to the radiographic examination performed during fabrication. The ultrasonic examination method, including calibration, instrumentation, scanning sensitivity, and coverage, is based on the requirements imposed by ASME, Section XI, Appendix I. Acceptance standards are equivalent or more restrictive than required by ASME, Section XI.

A stainless steel weld overlay is applied to the interior of the cylindrical shell and the steam outlet nozzle. Other nozzles and the RIP motor casing do not have cladding. The bottom head is clad with Ni-Cr-Fe alloy. The RIP penetrations are clad with Ni-Cr-Fe alloy or, alternatively, stainless steel.

The fracture toughness tests of pressure boundary ferritic materials, weld metal and heat-affected zone (HAZ) are performed in accordance with the requirements for ASME Code Class 1 vessel. Both longitudinal and transverse specimens are used to determine the minimum upper shelf energy (USE) level of the core beltline materials. Separate, unirradiated baseline specimens are used to determine the transition temperature curve of the core beltline base materials, weld metal, and HAZ.

For the vessel material surveillance program, specimens are manufactured from the material actually used in the reactor beltline region and weld typical of those in the beltline region, thus representing base metal, weld material, and the weld HAZ material. The plate and weld specimens are heat treated in a manner which simulates the actual heat treatment performed on the core region shell plates of the completed vessel. Each in-reactor surveillance capsule contains Charpy V-notch specimens of base metal, weld metal, and HAZ material, and tensile specimens from base metal and weld metal. Brackets are welded to the vessel cladding in the core belt region for retention of the detachable holders, each of which contains a number of the specimen capsules. Neutron dosimeters and temperature monitors are located within the capsules.

Access for examinations of the installed RPV is incorporated into the design of the vessel, biological shield wall, and vessel insulation.

Reactor Pressure Vessel Internals

The major reactor internal components included in the RPV System are:

(1) Core Support Structures

Shroud, shroud support (integral to the RPV and including the internal pump deck), core plate, top guide, fuel supports (orificed fuel supports and peripheral fuel supports), and control rod guide tubes.

(2) Other Reactor Internals

Control rods, feedwater spargers, RHR/ECCS low pressure flooding spargers, ECCS high pressure core flooding spargers and coupling, in-core guide tubes and stabilizers, core plate differential pressure (DP) lines, surveillance specimen holders, shroud head and steam separators assembly, and steam dryer assembly.

A general assembly drawing of these reactor internal components is shown in Figure 2.1.1a. The core support structures locate and support the fuel assemblies, form partitions within the reactor vessel to sustain pressure differentials across the partitions, and direct the flow of the coolant water.

The shroud support, shroud, and top guide make up a stainless steel cylindrical assembly that provides a partition to separate the upward flow of coolant through the core from the downward recirculation flow. This partition separates the core region from the downcomer annulus.

The core plate consists of a circular stainless steel plate with round openings and is stiffened with a rim and beam structure. The core plate provides lateral support and guidance for the control rod guide tubes, in-core flux monitor guide tubes, peripheral fuel supports and startup neutron sources. The last two items are also supported vertically by the core plate.

The top guide consists of a circular plate with square openings for fuel and with a cylindrical side forming an upper shroud extension. Each opening provides lateral support and guidance for four fuel assemblies or, in the case of peripheral fuel, less than four fuel assemblies. Holes are provided in the bottom, where the sides of the openings intersect, to anchor the in-core instrumentation detectors and start-up neutron sources.

The fuel supports are of two types: 1) peripheral and 2) orificed. The peripheral fuel supports are located at the outer edge of the active core and are not adjacent to control rods. Each peripheral fuel support supports one peripheral fuel assembly and contains an orifice to provide coolant flow to the fuel assembly. Each orificed fuel support supports four fuel assemblies vertically upward and horizontally and contains four orifices to provide coolant flow distribution to each fuel assembly. The orificed fuel supports rest on the top of the control rod guide tubes (CRGTs), which are supported laterally by the core plate. The control rods pass through cruciform openings in the center of the orificed fuel support.

The CRGTs located inside the vessel extend from the top of the CRD housings up through holes in the core plate. Each guide tube is designed as the guide for the lower end of a control rod and as the support for an orificed fuel support. This locates the four fuel assemblies surrounding the control rod. The lower end of the guide tube is supported by the CRD housing, which, in turn, transmits the weight of the guide tube, fuel supports, and fuel assemblies to the reactor vessel bottom head. The CRGTs also contain holes, near the top of the CRGT and below the core plate, for coolant flow to the orificed fuel supports.

The CRGT base is provided with a device for coupling the CRD with it. The CRD is restrained from ejection, in the case of a stub tube weld failure, by the coupling of the CRD with the CRGT base; in this event, the flange at the top of the guide tube will contact the core plate and restrain the ejection. The coupling will also prevent ejection if the housing fails at the stub tube weld; in this event, the guide tube remains supported on the intact upper housing.

The control rods are cruciform-shaped neutron absorbing members that can be inserted or withdrawn from the core by the CRD to control reactivity and reactor power.

Each of the two feedwater lines is connected to three spargers via three RPV nozzles. The feedwater spargers, which also function as ECCS high or low pressure flooding spargers (depending upon their connection to the line designated to receive high pressure or low pressure coolant flooding supply, respectively), are stainless steel headers located in the mixing plenum above the downcomer annulus. Each sparger, in two halves, with a tee connected in the middle, is fitted to each feedwater nozzle with the tee. The sparger tee inlet is connected to the RPV nozzle safe end by a double thermal sleeve arrangement. Feedwater flow enters the center of the spargers and is discharged radially inward to mix the cooler feedwater with the downcomer flow from the steam separators and steam dryer.

The design feature of the two residual heat removal (RHR) shutdown cooling system spargers, which also function as ECCS low pressure flooding (LPFL) spargers, is similar to that of the feedwater spargers. Two lines of RHR shutdown cooling system enter the reactor vessel through the two diagonally opposite nozzles and connect to the spargers. The sparger tee inlet is connected to the RPV nozzle safe end by a thermal sleeve arrangement.

The two ECCS high pressure core flooding (HPCF) spargers and couplings are the means for directing high pressure ECCS flow to the upper end of the core. Each of the two HPCF lines enters the reactor vessel through a diagonally opposite nozzle with a thermal sleeve arrangement. The curved sparger, including the connecting tee, is located around the inside of and is supported by the cylindrical portion of the top guide. The sparger tee is connected to the thermal sleeve by the HPCF coupling.

In-core guide tubes (ICGTs) protect the in-core flux monitoring instrumentation from flow of water in the bottom head plenum. The ICGTs extend from the top of the in-core housing to the top of the core plate. The local power range monitoring (LPRM) detectors for the Power Range Neutron Monitoring (PRNM) System and the detectors for the Startup Range Neutron Monitoring (SRNM) System are inserted through the guide tubes.

Two levels of stainless steel stabilizer latticework of clamps, tie bars, and spacers give lateral support and rigidity to the guide tubes. The stabilizers are connected to the shroud and shroud support.

The core plate differential pressure (DP) lines enter the reactor vessel through reactor bottom head penetrations. Four pairs of the core plate DP lines enter the head in four quadrants through four penetrations and terminate immediately above and below the core plate to sense the pressure in the region outside the bottom of the fuel assemblies and below the core plate during normal operation.

Surveillance specimen capsules, which are held in capsule holders mentioned earlier, are located at three azimuths at a com5/26/92mon elevation in the core beltline region. The capsule holders are non-safety-related internals. The capsule holders are mechanically retained by capsule holder brackets welded to the vessel cladding in order to allow their removal and reattachment.

The shroud head and steam separators assembly includes the connecting standpipes and forms the top of the core discharge mixture plenum. The steam dryer assembly removes moisture from the wet steam leaving the steam separators. The extracted moisture flows down the dryer vanes to the collecting troughs, then flows through tubes into the downcomer annulus. The shroud head and steam separators assembly and the steam dryer assembly are non-safety-related internals.

The core support structures are classified as Quality Group C, Seismic Category I. The design, materials, manufacturing, fabrication, examination, and inspection used in the construction of the core support structures meet the requirements of ASME Code Class CS structures. These structures are code-stamped accordingly. Other reactor internals are designed per the guidelines of ASME Code NG-3000 and are constructed so as not to adversely affect the integrity of the core support structures as required by NG-1122.

Special controls are exercised when austenitic stainless steel is used for construction of RPV internals in order to avoid cracking during service.

Design and construction of the RPV internals assure that the internals can withstand the effects of flow-induced vibration (FIV).

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.1.1a provides a definition of the inspection, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the Reactor Pressure Vessel System.

Table 2.1.1a: Reactor Pressure Vessel System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. System configuration of the Reactor Pressure Vessel (RPV) System is shown on Figure 2.1.1a. Key dimensions are presented in Table 2.1.1b, with design details of RPV lower plenum and core arrangement in Figures 2.1.1b and 2.1.1c, respectively.	1. Visual field inspections will be conducted of the installed RPV System key components identified in Section 2.1.1 and Figure 2.1.1a.	1. The installed configuration of the RPV System will be considered acceptable if it complies with Figures 2.1.1a, b, and c, Tables 2.1.1b and c, and Section 2.1.1.
2. The RPVS parameters used in LOCA analyses are identified in Table 2.1.1d.	2. Visual field inspections will be conducted of the inspection locations identified in Table 2.1.1d.	2. The installed configurations of the RPVS featues identified in Table 2.1.1d are acceptable if the associated areas are as noted in the table.
3. The reactor coolant pressure boundary (RCPB) portion of the RPV and appurtenances and their supports are classified as Quality Group A, Seismic Category I. These components are designed, fabricated, examined, and hydrotested in accordance with the rules of ASME Code Class 1 vessel or component support, and are code stamped accordingly. The core support structures are Quality Group C, Seismic Category I, and are designed, fabricated, and examined in accordance with the rules of ASME Code Class CS structures, and are code-stamped accordingly.	3. Inspections will be conducted of ASME Code required documents and the Code stamp on the components.	3. Existence of necessary ASME Code required documents and the Code stamps on the components confirm that the components in the RCPB portion of the RPV and the supports, and the core support structures are designed, fabricated and examined as ASME Code Class 1 and CS, respectively. This also confirms that the RPV is hydrotested per the ASME Code Class 1 requirements.
4. The RCPB of the RPV System retains its integrity under internal pressure that will be experienced during the service.	4. A hydrostatic test of the RCPB will be conducted in accordance with ASME Code requirements.	4. The results of the hydrostatic test must conform with the requirements in the ASME Code.

Table 2.1.1a: Reactor Pressure Vessel System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. The materials used for the RCPB portion of the RPV and appurtenances are low and high alloy steels with certain additional requirements for construction (Section 2.1.1). Special controls are exercised when austenitic stainless steel is used for construction of RPV internals in order to avoid cracking during service.	5. Inspection will be conducted of the records of materials, fabrication, and examination used in construction of the RCPB and austenitic stainless steel reactor internals.	5. Records of the materials and processes must confirm that the requirements specified for the RCPB in Section 2.1.1 are satisfied and that the manufacture and fabrication of the RPV internals made of austenitic stainless steel avoid potential for cracking in service.
6. The ferritic materials used in the RCPB portion of the RPV and appurtenances are not susceptible to brittle fracture under pressure during the service.	6. Fracture toughness tests of the ferritic base, weld and heat-affected zone (HAZ) metal used in the RCPB will be conducted in accordance with the requirements for ASME Class 1 components.	6. Records of the fracture toughness data of the RCPB ferritic materials must confirm that 1) the requirements of the ASME Code are met, and 2) the reactor vessel beltline materials will not be susceptible to brittle fracture during the service.
7. Specimens for the surveillance program are selected from the vessel base metal and weld metal.	7. Inspection will be conducted of the records of the specimens selected from the reactor beltline region.	7. The specimens, with respect to location and orientation, types (tensile or Charpy V-notch), and quantities, must meet the requirements of ASTM E-185.
8. Analysis for vibration prediction is performed to assure that design and construction of the RPV internals can withstand the effects of flow-induced vibration (FIV). The design analysis is based on predicted values of FIV loads. The vibration prediction analysis may be upgraded by available test data.	8. A vibration test will be conducted of the reactor internals to verify the adequacy of the internals design, manufacture, and assembly with respect to the potential effects of FIV. The first-of-a-kind prototype internals will be flow tested by vibration instrumentation followed by inspection for damage. The internals in subsequent plants will be flow tested, but without vibration instrumentation, followed by inspection for damage.	8. Reactor vessel internals vibration is considered acceptable when results of the vibration measurement are compared with results of the vibration prediction analysis to verify compliance with design limits, and when inspection of the internals indicate no sign of damage, loose parts, or excessive wear in the prototype test. The vibration of reactor internals in subsequent plants is considered acceptable when inspection of the internals indicate no sign of damage, loose parts, or excessive wear.

Table 2.1.1a: Reactor Pressure Vessel System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9. Access for examinations of the RPV is incorporated into the design of the vessel, biological shield wall and vessel insulation.	9. Visual inspection will be conducted of accessibility for examinations of the vessel and welds.	9. Provisions for access in the design of the vessel, biological shield wall, and vessel insulation shall be, in the minimum, as follows: The shield wall and vessel insulation behind the shield wall must be spaced away from the RPV outside surface. Access for the insertion of automated devices must be provided through removable insulation panels at the top of the shield wall and at access ports at reactor vessel nozzles. Access to the RPV welds above the top of the biological shield wall must be provided by removable insulation panels. The closure head must have removable insulation to provide access for manual ultrasonic examinations of its welds. Access to the bottom head to shell weld must be provided through openings in the RPV support pedestal and removable insulation panels around the lower cylindrical portion of the vessel. Access must be provided to partial penetration nozzle welds (i.e., CRD penetrations, instrumentation nozzles and recirculation internal pump penetration welds) for performance of visual examinations. Access must be provided for examination of the attachment weld between the support skirt knuckle (forged integrally on the shell ring) and the RPV support skirt. Access must be provided to the balance of the support skirt for performance of visual examination.

Table 2.1.1b: Key Dimensions of RPVS Components

Description	Elevation/ Dimension (Figure 2.1.1a)	Nominal Value (mm)
RPV inside diameter (inside cladding)	G	7112.0
RPV wall thickness in beltline (without cladding)	H	174.0
RPV bottom head inside invert	A	0.0
Top of RPV flange	F	17703.0
RPV support skirt bottom	B	3200.0
RPV stabilizer connection	E	13766.0
Shroud outside diameter	L	5550.0
Shroud wall thickness	M	50.8
Steam nozzle ID at pipe connection	K	642.0
Core plate support/Top of shroud middle flange	C	4695.2
Top guide support/Top of shroud top flange	D	9351.2
Shroud support legs (Fig. 2.1.1b)	NxQ	153.0x662.0
Control rod guide tube OD	P	273.05

Table 2.1.1c: Acceptable Variations of Dimensions and Elevations

Description	Elevation/ Dimension (Figure 2.1.1a)	Variation (mm)
RPV inside diameter (inside cladding)	G	±50.0
RPV wall thickness in beltline (without cladding)	H	+14.0/-3.0
RPV bottom head inside invert	A	Reference 0.0
Top of RPV flange	F	±25.0
RPV support skirt bottom	B	+50.0/-10.0
RPV stabilizer connection	E	±15.0
Shroud outside diameter	L	±20.0
Shroud wall thickness	M	±2.0
Steam nozzle ID at pipe connection	K	+8.0/-0.0
Core plate support/Top of shroud middle flange	C	±10.0
Top guide support/Top of shroud top flange	D	±13.1
Shroud support legs (Fig. 2.1.1b)	NxQ	±6.0 (for N and Q)
Control rod guide tube OD	P	±2.5

Table 2.1.1d:

RPVS Parameters Used in LOCA Analyses		
Line	Inspection Location	Postulated Break Area (mm^2)
Steamline	Flow element throat diameter in the steam outlet nozzle.	98480
Feedwater	Inside diameters of flow nozzles on the three spargers of a line for the total flow area.	83890
RHR Injection	Inside diameters of flow nozzles on the three spargers of a line for the total flow area.	20530
High Pressure Core Flooder	Inside diameters of flow nozzles on the three spargers of a line for the total flow area.	9200
RHR Shutdown Cooling	Inside diameter of an RHR shutdown outlet nozzle.	79150
Drain	Inside diameter of the bottom head drain outlet nozzle at the inside surface of the head.	2030
Note: The areas calculated from the inspections shall not exceed the postulated break areas by 5 percent.		

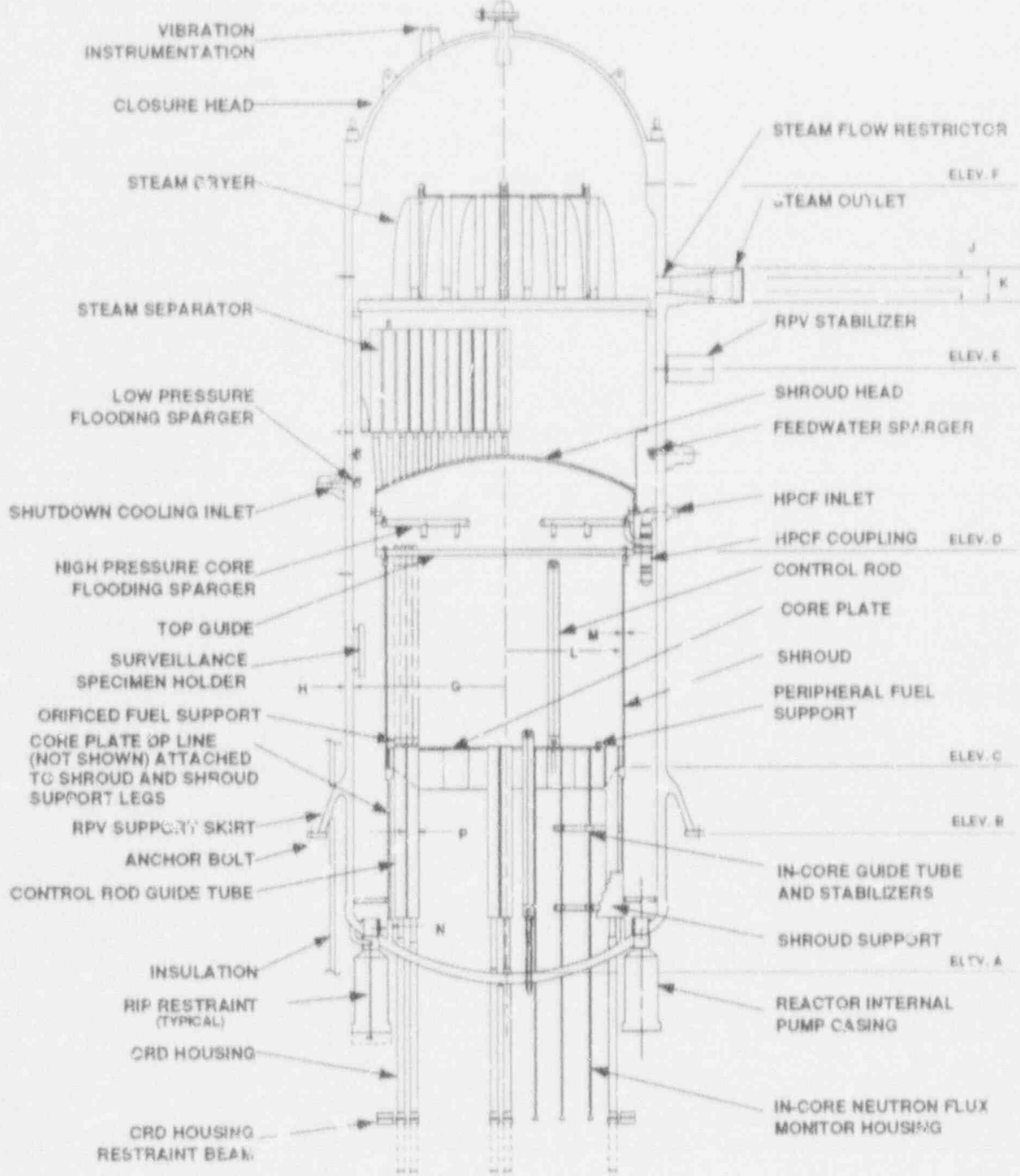


Figure 2.1.1a Reactor Pressure Vessel System Key Features

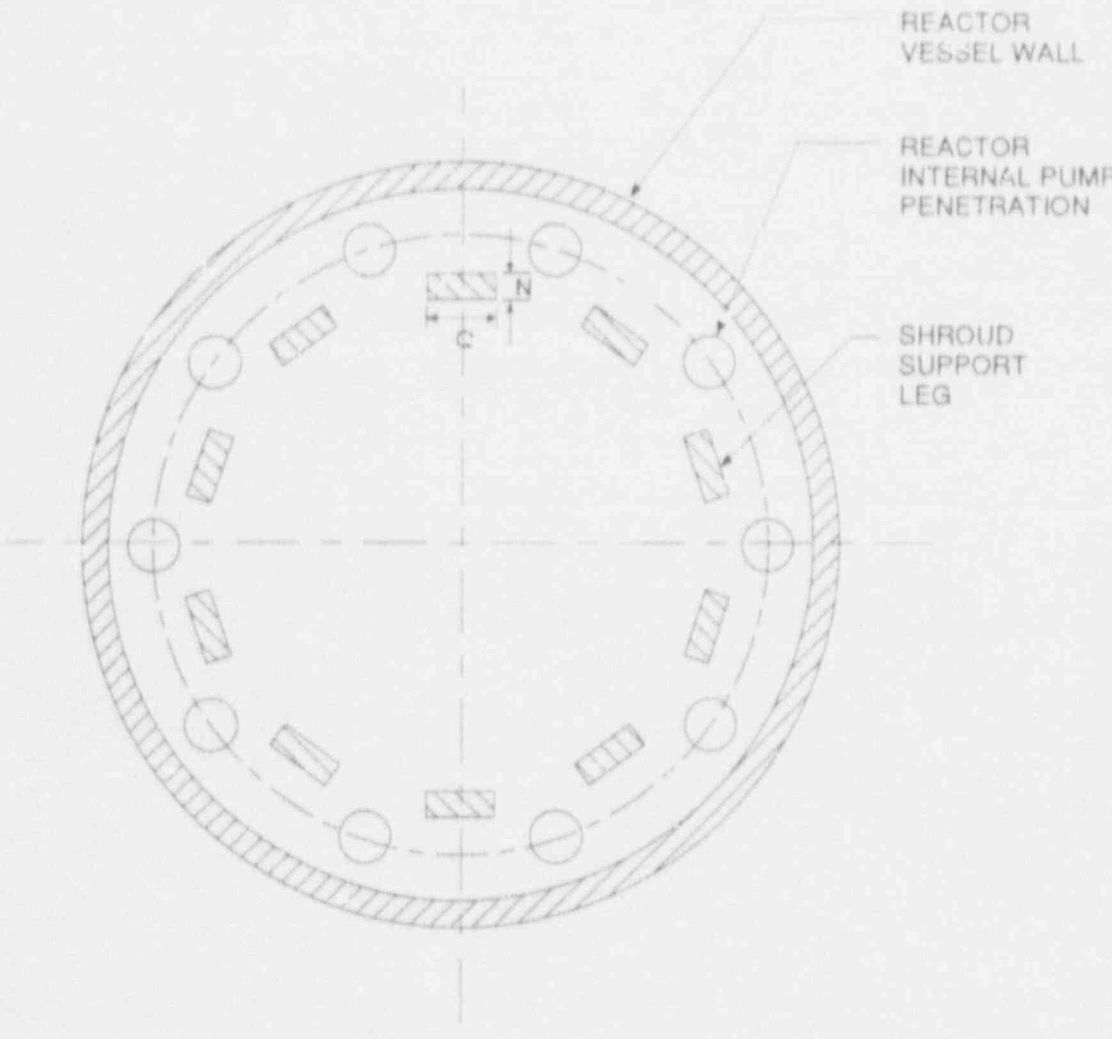


Figure 2.1.1b Pump and Shroud Support Leg Arrangement

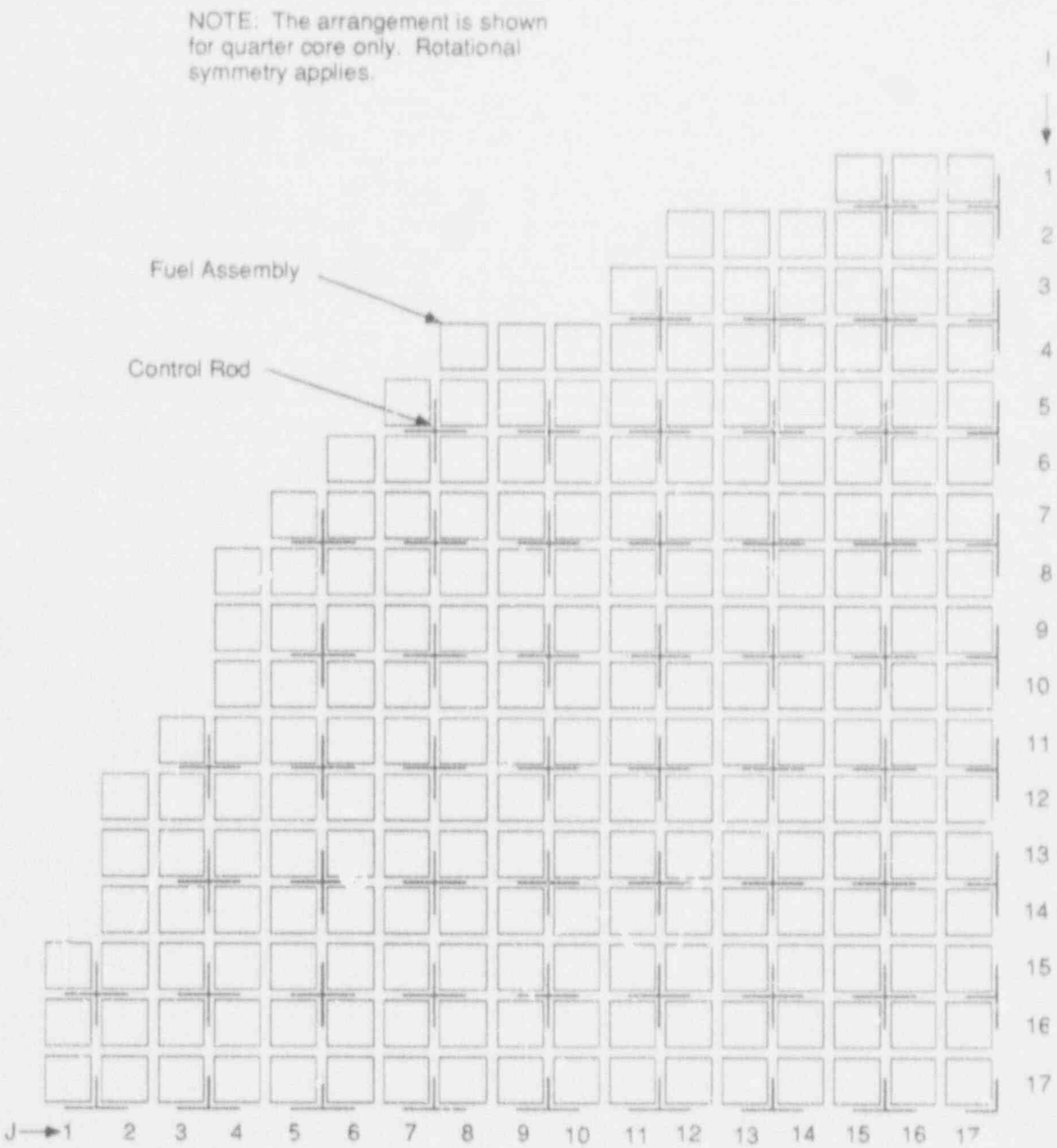


Figure 2.1.1c Core Arrangement

2.1.2 Nuclear Boiler System

Design Description

General System Description

The primary functions of the Nuclear Boiler System (NBS) are: (1) to deliver steam from the Reactor Pressure Vessel (RPV) to the Main Steam System (MSS), (2) deliver feedwater from the Condensate, Feedwater, and Air Extraction System to the RPV, (3) overpressure protection of the Reactor Coolant Pressure Boundary (RCPB), (4) automatic depressurization of the RPV in the event of a Loss of Coolant Accident (LOCA) where the RPV does not depressurize rapidly and the high pressure makeup systems fail to adequately maintain the water level in the RPV, and (5) with the exception of monitoring the neutron flux, providing the instrumentation necessary to monitor the conditions in the RPV. This includes the RPV pressure, metal temperature, and water level instrumentation.

Figures 2.1.2a and 2.1.2b show the general configuration of the Main Steam Lines (MSLs), the Safety/Relief Valves (SRVs), and the SRV discharge lines. The SRVs perform the dual function of overpressure protection and automatic depressurization of the RPV. Figure 2.1.2c show the general configuration of the Feedwater (FW) lines.

The MSLs are designed to direct steam from the RPV to the MSS, the FW lines to direct feedwater from the FW System to the RPV, and the RPV instrumentation to monitor the conditions within the RPV, over the full range of reactor power operation.

The NBS contains the valves necessary for isolation of the MSLs, feedwater lines, and their drain lines at the primary containment boundary.

The NBS also contains the RPV head vent line and non-condensable gas removal line.

Main Steam Lines

The NBS does not contain all of the MSLs. The NBS contains only the portion of the MSLs from their connection to the Reactor Pressure Vessel (RPV) to the boundary with the Main Steam System (MSS), which occurs at the seismic interface located downstream of the outboard Main Steam Isolation Valves (MSIVs).

The main steam lines are Quality Group A from the RPV out to and including the outboard MSIVs, and Quality Group B from the outboard MSIVs to the turbine stop valves. They are Seismic Category I from the reactor pressure vessel out to the seismic interface.

To support the safety analysis, the total steam volume of the steam lines, from the RPV to the main steam turbine stop valves and turbine bypass valves, shall be greater than or equal to 113.2 m^3.

MSL flow limiter

Each MSL has a flow limiter. The MSL flow limiter consists of a flow restricting venturi which is located in each RPV MSL outlet nozzle. The restrictor limits the coolant blowdown rate from the RPV in the event a MSL break occurs outside the containment to a (choke) flow rate equal to or less than 200% of rated steam flow at 72.1 kg/cm^2 g upstream pressure.

The MSL flow limiter also serves as a flow element to monitor the MSL flow. Instruments lines are provided to monitor the pressure at the throat of the MSL flow limiter. The RPV steam dome pressure instrument lines are used to provide the pressure upstream of the MSL flow limiter.

The MSL flow limiters are designed to limit the loss of coolant from the RPV following a MSL rupture outside the containment to the extent that the RPV water level remains high enough to provide cooling within the time required to close the MSIVs.

The MSL flow limiter has no moving parts.

Main Steam Isolation Valves

Two isolation valves are welded in a horizontal run of each of the four main steam lines; one valve inside of the drywell, and the other is near the outside of the primary containment pressure boundary.

The MSIVs are Y-pattern globe valves. 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 Y-pattern permits the inlet and outlet passages to be streamlined; this minimizes pressure drop during normal steam flow.

The primary actuation mechanism utilizes a pneumatic cylinder; the speed at which the valve opens and closes can be adjusted. Helical springs around the spring guide shafts will close the valve if gas pressure in the actuating cylinder is reduced.

The MSIV quick-closing speed is ≥ 3 and ≤ 4.5 seconds when N_2 or air pressure is admitted to the upper piston compartment. The valve can be test closed with a 45-60 second slow closing speed by admitting N_2 or air to both the upper and low piston compartments.

Feedwater Lines

The NBS does not contain all of the FW lines. The NBS contains only the portion of the FW lines from the seismic interface located upstream of the Motor-Operated Valves (MOVs) to their connections to the RPV. Figure 2.1.2c shows the portion of the FW lines within the NBS.

The FW piping consists of two 550A (22-inch) diameter lines from the FW supply header. Isolation of each line is accomplished by two containment isolation valves consisting of one check valve inside the drywell and one positive closing check valve outside the containment. Also included in this portion of the line is a manual maintenance valve located between the inboard isolation valve and the reactor nozzle. The feedwater line upstream of the outboard isolation valve contains a remote, manual, Motor-Operated (MO) gate valve, and a seismic interface restraint. The outboard isolation valve and the MO gate valve provide a quality group transitional point in the feedwater lines.

The feedwater piping is Quality Group A from the RPV out to and including the outboard isolation valve, Quality Group B from the outboard isolation valve to and including the MO gate valve, and Quality Group D upstream of the MO gate valve. The feedwater piping and all connected piping of 65A (2 1/2 - inch) or larger nominal size is Seismic Category I from the RPV to the seismic interface.

Safety/Relief Valves

The nuclear pressure relief system consists of SRVs located on the MSLs between the RPV and the first isolation valve, i.e. the inboard MSIV, within the drywell. These valves protect against overpressure of the nuclear system.

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% of the design pressure (1.10 x 87.9 kg/cm^{2}g = 96.7 kg/cm^{2}g) for design basis events which cause the RPV pressure to rise.

The SRV discharge line is designed to achieve critical flow conditions through the valve, thus providing flow independence to discharge pipe losses. Each SRV has its own discharge line. The SRV discharge lines terminate at the quenchers located below the surface of the suppression pool.

The SRVs provide three main protection functions:

(1) Overpressure safety operation: The valves function as safety valves and open to prevent nuclear system overpressurization - they are self-actuating by inlet steam pressure if not already signaled open for relief operation.

The safety (steam pressure) mode of operation is initiated when direct and increasing static inlet steam pressure overcomes the restraining spring and frictional forces acting against the inlet steam pressure at the main disc or pilot disc and the main disc moves in the opening direction. The condition at which this action is initiated corresponds to the set-pressure value stamped on the nameplate of the SRV.

(2) Overpressure relief operation: The valves are opened using a pneumatic actuator upon receipt of an automatic or manually initiated signal to reduce pressure or to limit pressure rise.

The relief (power actuated) mode of operation is initiated when an electrical signal is received at any of the solenoid valves located on the pneumatic actuator assembly. The solenoid valve(s) will open, allowing pressurized air to enter the lower side of the pneumatic cylinder which pushes the piston and the rod upwards. This action pulls the lifting mechanism of the main or pilot disc thereby opening the valve to allow steam to discharge through the SRV until the inlet pressure is near or equal to zero.

For overpressure relief valve operation (power-actuated mode), pressure sensors on the RPV generate a RPV high pressure trip signal which is used to initiate opening the SRVs. When the set pressure is reached, the SRV power-actuated relief solenoid is energized, which admits pneumatic pressure to the SRV actuator, thereby opening the SRV.

The SRV pneumatic operator is so arranged that, if it malfunctions, it will not prevent the SRV from opening when steam inlet pressure reaches the spring lift setpoint.

(3) Depressurization operation: The Automatic Depressurization System (ADS) valves open automatically as part of the Emergency Core Cooling System (ECCS) for events involving small breaks in the nuclear system process barrier.

Eight of the eighteen SRVs are designated as ADS valves and are capable of operating from either ADS logic or safety/relief logic signals. Automatic depressurization by the ADS is provided to reduce the reactor pressure during a LOCA in which the High Pressure Core Flooder (HPCF) System and/or the Reactor Core Isolation Cooling (RCIC) System are unable to restore water level. This allows makeup of core cooling water by the low pressure makeup system (the Low Pressure Flooder (LPFL) Mode of the Residual Heat Removal (RHR) System).

The ADS consists of redundant trip channels arranged in two separated logics that control two separate solenoid-operated gas pilots, ADS 1 and ADS 2, on each ADS SRV. Either pilot can operate the ADS valve. These pilots control the pneumatic pressure applied by the accumulators and the High Pressure Nitrogen Gas Supply (HPIN) System. The instrumentation and logic power is obtained from the Safety System Logic and Control (SSLC) Division I and II

Sensors from all four divisions and Division I control logic for low reactor water level and high drywell pressure initiate ADS 1 pilots, and sensors from all four divisions and Division II initiate ADS 2 pilots, either of which will initiate the opening of the ADS SRVs.

The reactor vessel low water level initiation setting for ADS is pre-selected to depressurize the reactor vessel in time to allow adequate cooling of the fuel by the network of ECCS following a LOCA. Timely depressurization of the reactor vessel is provided if the reactor water level drops below preset limits together with an indication that high drywell pressure has occurred, which signifies there is a loss of coolant into the containment with insufficient high pressure makeup to maintain reactor water level. For breaks outside the containment, timely depressurization of the reactor vessel is provided if the reactor water level drops below preset limits for a time period sufficient for the ADS high drywell pressure bypass timer and the ADS timer to time-out.

All SRVs have individual non-safety related accumulators. In addition, those with ADS function have a separate safety-related larger capacity accumulators with separate redundant gas power actu[illegible]

The ADS accumulators are sized to operate the SRV two times with the drywell pressure at 70% of design gauge pressure following failure of the pneumatic supply to the accumulator.

The SRVs can be operated individually in the power-actuated mode by remote manual switches located in the main control room.

NBS Instrumentation

The purpose of the NBS RPV instrumentation is to monitor and provide control input for operation variables during plant operation.

The NBS contains the instrumentation for monitoring the reactor pressure, metal temperature, and water level. The reactor pressure and water level instruments are used by multiple Boiling Water Reactor (BWR) systems, both safety related and non-safety related.

Pressure indicators and transmitters detect reactor vessel internal pressure from the same instrument lines used for measuring reactor vessel water level.

RPV coolant temperatures are determined by measuring saturation pressure (which gives the saturation temperature), outlet flow temperature to the Reactor Water Cleanup (CUW), and RPV bottom head drain line temperature. Reactor vessel outside surface (metal) temperature are measured at the head flange and the bottom head locations. Temperatures needed for operation and for operating limits are obtained from these measurements: During normal operation, either reactor steam saturation temperature and/or inlet temperatures of the reactor coolant to the CUW System and the RPV bottom head drain can be used determine the RPV coolant temperature.

Figure 2.1.2e shows the water level and RPV penetrations for each water level range. The instruments that sense the water level are all differential pressure devices calibrated for a specific RPV pressure (and corresponding liquid temperature) conditions. The water level measurement design is the condensate reference chamber type. Instrument zero for all the RPV water level ranges is the top of the active fuel. The following is a description of each water level range shown on Figure 2.1.2e.

(1) Shutdown Range Water Level.

This range is used to monitor the reactor water level during shutdown condition when the reactor system is flooded for maintenance and head removal. The two RPV instrument penetrations elevations used for this water level measurement are located at the top of the RPV head and the instrument tap just below the dryer skirt.

(2) Narrow Range Water Level.

This range is used to monitor reactor water level during normal power operation. This ranges uses the RPV taps at the elevations near the top of the steam outlet nozzles and the taps at the elevation near the bottom of the dryer skirt. The Feedwater Control (FDWC) System uses this range for its water level control and indication inputs.

(3) Wide Range Water Level.

This range is used to monitor reactor water level for events where the water level exceeds the range of the narrow range water level instrumentation, and is used to generate the low reactor water level trip signals which indicate a potential LOCA. This range uses the RPV taps at the elevations near the top of the steam outlet nozzles and the tap below the Top of the Active Fuel (TAF).

(4) Fuel Zone Range Water Level.

This range is provided for the post accident monitoring, and provides the capability to monitor the reactor water level below the wide range water level instrumentation. This range uses the RPV taps at the elevations near the top of the steam outlet nozzles and the taps below the TAF (above pump deck).

The NBS contains the instrument lines to monitor the differential pressure across the RPV pump deck and core support plate. The instrumentation which actually performs these functions is located within the Recirculation Flow Control (RFC) System.

The SRVs are provided with position sensors which provide positive indication of SRV disk/stem position.

Thermocouples are located in the discharge exhaust pipe of the SRVs. The temperature signal goes to a multipoint recorder with an alarm and will be activated by any temperature in excess of a set temperature signaling that one of the SRV seats has started to leak.

The NBS also contains the drywell pressure instrumentation used to generate the safety related high drywell pressure trip LOCA signal, which is used by many of the safety related systems to initiate safety actions. The Reactor Protection System (RPS) utilizes this signal as a scram initiation signal. The Leak Detection and Isolation System (LDS) utilizes this signal to initiate containment isolation. The Emergency Core Cooling Systems (ECCSs) utilizes this signal as a system initiation signal.

Control room indication and/or alarms are provided for the important plant parameters monitored by the NBS.

ASME Code Requirements

The major mechanical components are designed to meet American Society of Mechanical Engineers (ASME) Code Requirements as shown below:

Component	ASME Code Class	Design Conditions Pressure	Design Conditions Temperature
FW lines from the MOVs to the outboard containment isolation check valves	2	87.9 kg/cm^{2}g (1250 psig)	302°C (575°F)
FW lines from the outboard containment isolation check valve to the RPV	1	87.9 kg/cm^{2}g (1250 psig)	302°C (575°F)
Feedwater (FW) line outboard containment isolation check valve	1	87.9 kg/cm^{2}g (1250 psig)	302°C (575°F)
Main Steam Isolation Valves (MSIVs)	1	96.7 kg/cm^{2}g (1375 psig)	308°C (586.°F)
Safety/Relief Valves (SRVs)	1	96.7 kg/cm^{2}g (1375 psig)	308°C (586.°F)
Main Steam Lines (MSLs), from Reactor Pressure Vessel (RPV) to outboard MSIVs	1	87.9 kg/cm^{2}g (1250 psig)	302°C (575°F)
MSLs from the outboard MSIVs to the seismic interface restraint	2	87.9 kg/cm^{2}g (1250 psig)	302°C (575°F)
SRV discharge line piping, from the SRVs to the diaphragm floor	3	38.0 kg/cm^{2}g (540 psig)	250°C (482°F)
SRV discharge line piping, from the diaphragm floor to the suppression pool surface	2	38.0 kg/cm^{2}g (540 psig)	250°C (482°F)

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.1.2 provides a definition of the instructions, tests and/or analyses together with associated acceptance criteria which will be undertaken for the NBS.

Table 2.1.2: Nuclear Boiler System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Test, Analysis	Acceptance Criteria
1. A simplified configuration of the Main Steam Lines (MSLs), and Feedwater (FW) lines within the Nuclear Boiler System (NBS) scope, and the Safety/Relief Valve (SRVs) and the Safety/Relief Valve (SRV) discharge lines, as described in Section 2.1.2 and shown in Figures 2.1.2a, 2.1.2b, and 2.1.2c.	1. Visual field inspection will be conducted to confirm that the installed equipment is in compliance with the design configuration defined in Figures 2.1.2a, 2.1.2b, and 2.1.2c.	1. The system configuration is in accordance with Figures 2.1.2a, 2.1.2b, and 2.1.2c.
2. The Reactor Coolant Pressure Boundary (RCPB) portions of the NBS are classified as American Society of Mechanical Engineers (ASME) Code Class 1. They are designed, fabricated, examined and hydrotested per the rules of the ASME Code, Section III. This includes the MSLs from the Reactor Pressure Vessel (RPV) to and including the outboard Main Steam Isolation Valves (MSIVs), the FW lines from the outboard positive closing check valves to the RPV.	2. Inspections will be conducted of ASME Code required documents and the Code stamp on the actual components to verify that they have been manufactured per the relevant ASME requirements.	2. The components have appropriate ASME Code, Section III, Class 1 certifications and Code Stamps.
3. Each Main Steam Line (MSL) shall have a flow limiter located in the RPV MSL outlet nozzle. The MSL flow limiter shall limit the coolant blowdown rate from the RPV in the event of a MSL break to a (choke) flow rate equal to, or less than 200% of rated steam flow at 72.1 kg/cm^{2}g upstream pressure.	3. Using the as-built dimensions, perform an analysis which shows that the MSL flow limiters satisfy the requirement.	3. Analysis confirms that the MSL flow limiters perform their intended function.
4. Each MSL flow limiter has taps for two instrument lines. These instrument lines are used for monitoring the flow through each MSL.	4. Visual inspection will be conducted to confirm that the MSL instrument lines have been installed in compliance with design commitment.	4. Inspection confirm that the MSL flow instrument lines have been installed.

Table 2.1.2: Nuclear Boiler System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Test, Analysis	Acceptance Criteria
5. The total steam line volume from the RPV to the main steam turbine stop valves and steam bypass valves shall be greater than or equal to 113.2 m^3.	5. Using the as designed configuration of the steam lines perform calculations to determine the main steam line volume.	5. Calculations confirms that the steam line volume satisfies the design requirement.
6. The MSIVs meet the requirements of ASME Code, Section III.	6. Inspections will be conducted of ASME Code required documents and the Code Stamp on the actual components to verify that they have been manufactured per the relevant ASME requirements.	6. The MSIVs have appropriate ASME Code, Section III, Class 1 certifications and code stamps.
7. The Main Steam Isolation Valve (MSIV) closing time shall be between 3 and 4.5 seconds when N_2 or air is admitted into the valve pneumatic actuator.	7. Pre-operational tests will be conducted to demonstrate proper operation of the MSIVs, including verification of the closure time.	7. Pre-operational tests confirms that the MSIVs satisfy the closure time requirement.
8. The SRVs meet the requirements of ASME Code, Section III.	8. Inspections will be conducted of ASME Code required documents and the Code Stamp on the actual components to verify that they have been manufactured per the relevant ASME requirements.	8. The SRV have appropriate ASME Code, Section III, Class 1 certifications and code stamps.
9. There shall be 18 SRVs mounted on the MSLs as shown in Figure 2.1.2a. The required spring set pressure and capacities are given in Table 2.1.2a. The SRVs shall meet the opening performance shown in Figure 2.1.2f.	9. Inspections will be conducted to confirm that the SRVs have the required (nominal) spring set pressure and (minimum) capacity on the SRV nameplate. Visual inspections will be conducted to confirm that all 18 SRVs have been installed in their proper locations. Review of the qualification test data for the particular SRV model selected to confirm that the opening performance complies with the requirements.	9. Inspection confirms that the SRVs have the required capacities and set pressures identified on their name plates. Inspections confirms that the proper capacity and set pressure SRV has been mounted in its correct location. Confirm that the selected SRV model satisfies the performance requirements.

Table 2.1.2: Nuclear Boiler System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Test, Analysis	Acceptance Criteria
10. The SRVs shall be provided with instrumentation which will provide positive indication (i.e. by direct measurement) of SRV position.	10. Inspection will be performed that the SRVs have positive position indication instrumentation, and that the instrumentation has been properly connected.	10. Inspection confirms that the SRVs have positive position indication.
11. A simplified configuration of the Automatic Depressurization System (ADS) SRVs and the non-ADS SRVs as described in Section 2.1.2 and Figure 2.1.2.d. There are 8 ADS SRVs and 18 non-ADS SRVs.	11. Visual field inspection will be conducted to confirm that the installed equipment is in compliance with Figure 2.1.2d.	11. The configuration is in accordance with Figure 2.1.2d.
12. Upon receipt of a either a high drywell pressure trip signal current with a RPV low water level 1 trip signal of sufficient duration for the ADS timer to time-out, or a RPV low water level 1 trip signal of sufficient duration for the ADS high drywell pressure bypass timer and the ADS timer to time-out, the ADS logic generates a ADS initiation signal to the SRV ADS solenoids.	12. Logic and instrument functional testing shall be performed to demonstrate that the ADS logic performs as required.	12. The drywell pressure and RPV water level instrumentation, as well as the ADS logic, functions as required to generate the ADS initiation signal.
13. The SRV discharge lines shall terminate at the quenchers located below the surface of the suppression pool.	13. Visual inspections will confirm that the SRV discharge line quenchers have been installed.	13. Inspection confirms that the SRV discharge line quenchers have been installed.
14. The RPV shall be provided with instrument lines and instrumentation necessary to monitor the RPV steam dome pressure and the RPV water level from the Bottom of the Active Fuel (BAF) to top of the steam dome.	14. Visual inspections will be performed to confirm that the instrument lines and instrumentation for the RPV steam dome pressure, the RPV shutdown range water level, the RPV narrow range water level, the RPV wide range water level, and the RPV fuel zone range water level sensors has been properly installed.	14. Inspection confirms that the instrumentation has been properly installed.
15. For the safety related NBS instrumentation, the instrumentation be capable of performing its necessary function.	15. Instrument functional testing shall be performed to demonstrate that the instrumentation performs as required.	15. The instrumentation functions as required.

Table 2.1.2: Nuclear Boiler System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Test, Analysis	Acceptance Criteria
16. Control room indication/alarms are provided for the important plant parameters monitored by the NBS.	16. Inspection shall be performed which confirms that the important plant parameters monitored by the NBS are indicated and/or alarmed in the main control room.	16. Inspection confirms that the important plant parameters have been indicated and/ or alarmed in the main control room.

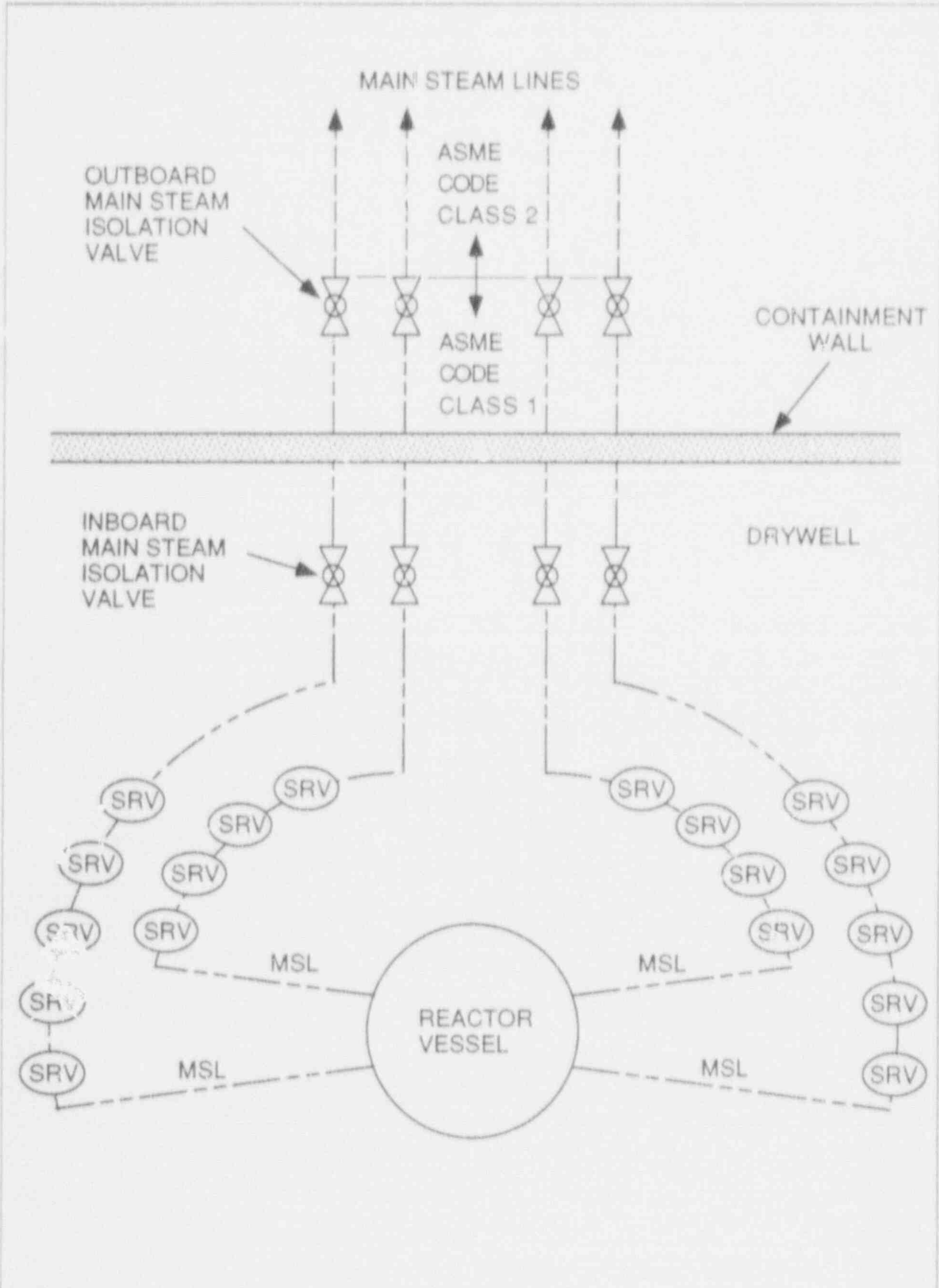


Figure 2.1.2a Safety/Relief Valves and Steamline

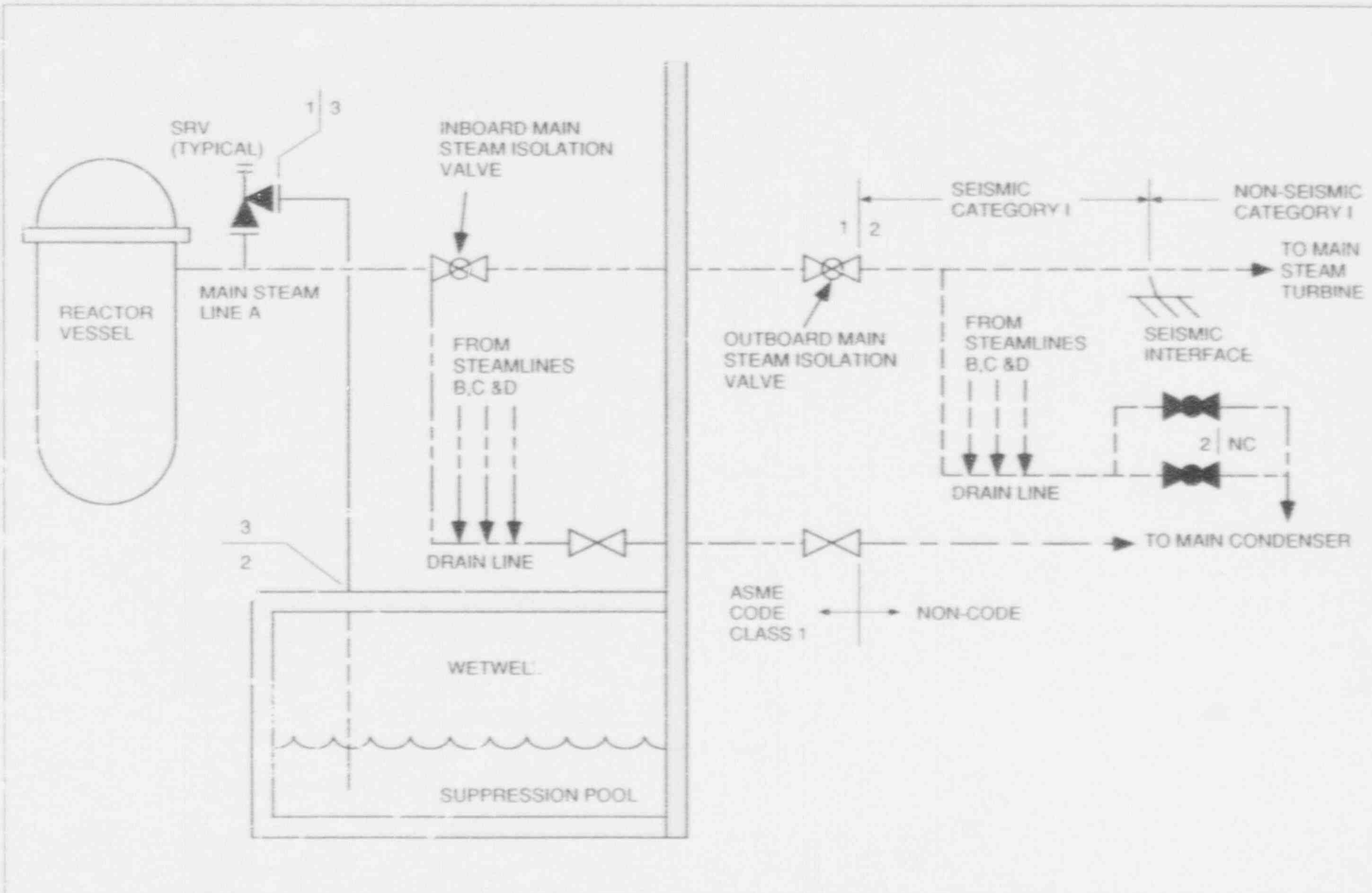


Figure 2.1.2b Steamline

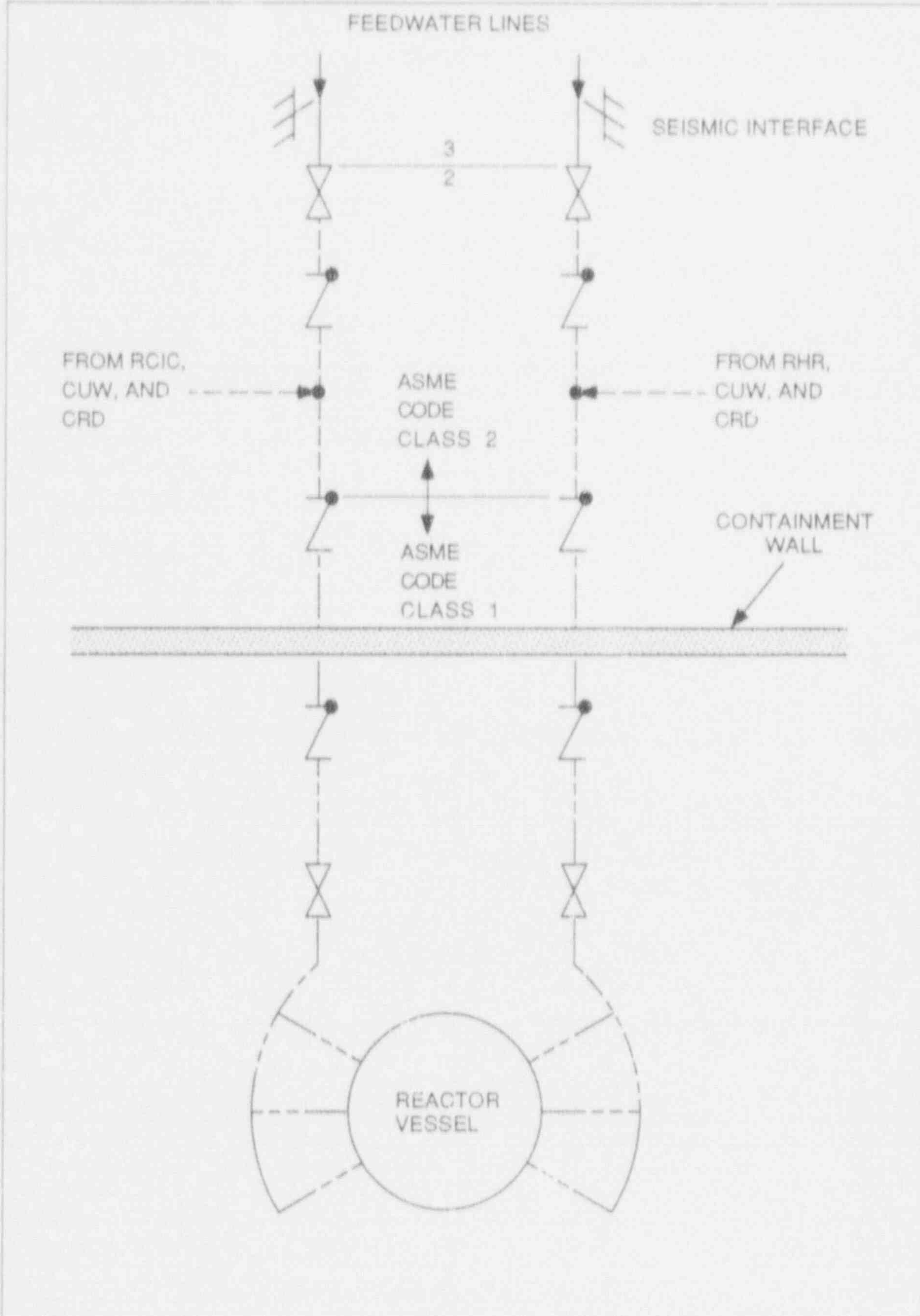


Figure 2.1.2c Feedwater Line

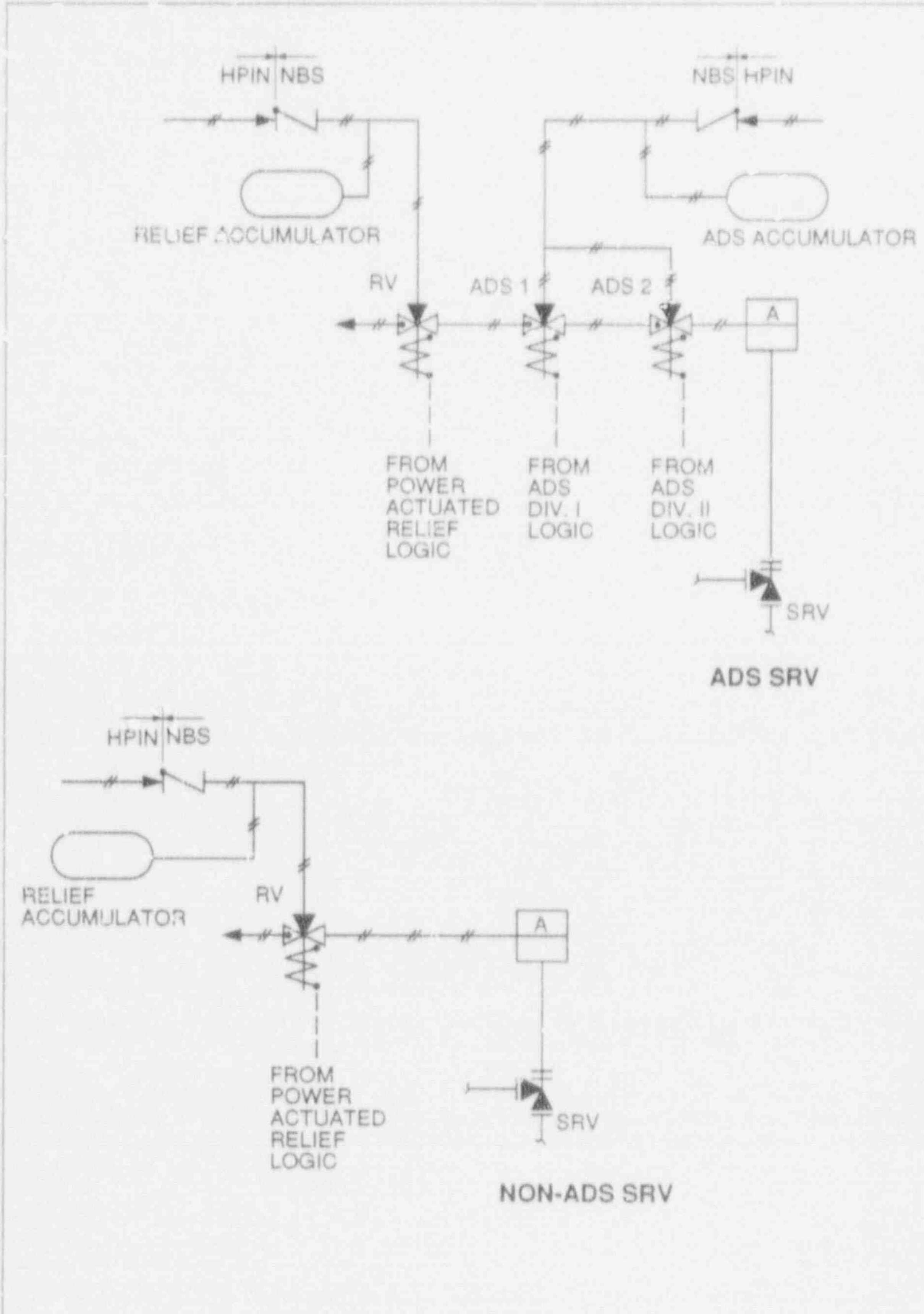


Figure 2.1.2d Safety/Relief Valve Pneumatic Lines

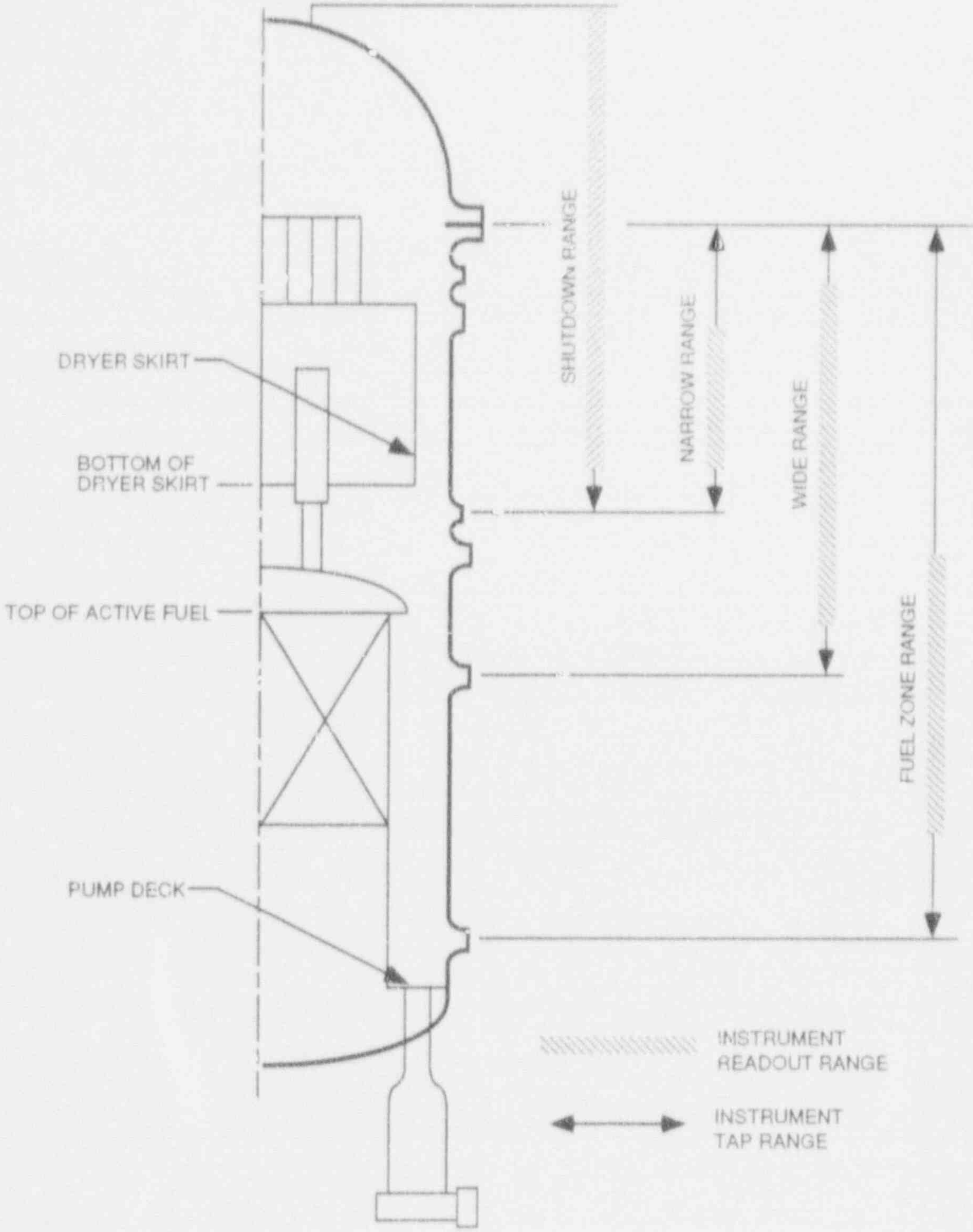


Figure 2.1.2e Water Level Range Definition

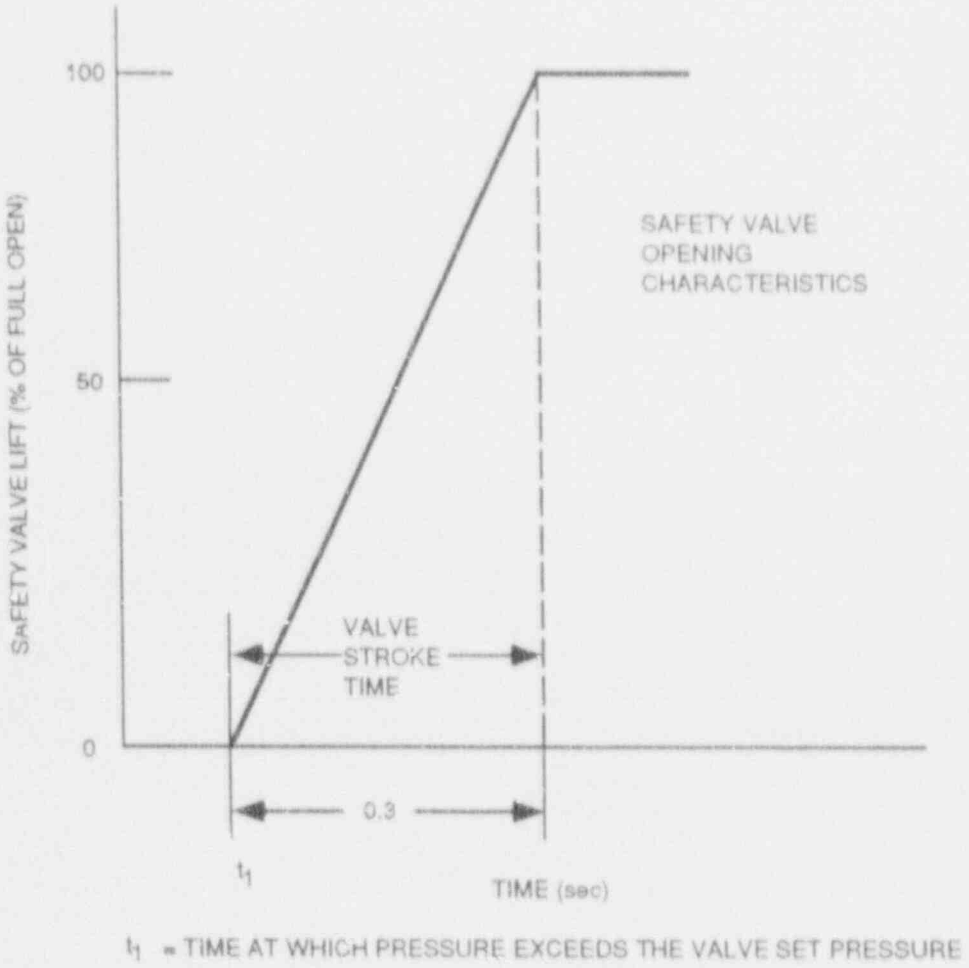


Figure 2.1.2f Safety-action Valve Lift Characteristics

2.1.3 Reactor Recirculation System

Design Description

The Reactor Recirculation System (RRS) includes an arrangement of 10 reactor internal (seal-less) pumps (RIP) with wet motors mounted in the bottom of the RPV as shown in Figure 2.1.3. The RIPs circulate coolant through the reactor core at variable flow rates, which vary reactor power approximately 70-100%.

Core coolant flow rate is controlled by the Recirculation Flow Control (RFC) System. The RFC System includes the Adjustable Speed Drive (ASD), RIP trip (RPT) function and core flow measurement. Tier 1 information for the RFCS is in Section 2.2.8.

In addition to providing core coolant flow during normal reactor operation, the RIPs and associated equipment are designed to (1) have flow coastdown characteristics that provide an adequate fuel thermal margin during plant transients, and (2) maintain reactor coolant pressure boundary (RCPB) integrity during adverse combinations of loading during abnormal, accident, and special event conditions.

The only safety-related portion of the RRS is the bottom motor cover bolted to the RIP motor housing. The RIP motor housing is part of the RPV described in Section 2.1.1. The motor cover is part of the RCPB and is designed to Seismic Category I and Quality Group A (similar to the RPV). The design, materials, manufacturing, fabrication, testing, examination, and inspection used in the construction of the cover and cover bolts and nuts meet requirements of ASME Code Class 1 vessels. The motor cover and cover bolt materials are low or high alloy steels.

Hydrostatic test of the covers and bolts after fabrication and in the plant is performed in accordance with the requirements for ASME Code Class 1 vessels.

The RIP design parameters are:

• RIP Motor Cover Design Pressure (kg/cm^2 g)	87.9
• RIP Motor Cover Design Temperature (°C)	302
• Individual RIP rated Flow (m^3/hr)	≥ 6912
• Rated Total Developed Head (TDH) for RIP (m)	≥ 32.6

The RIP and core flows are measured in various plant operating modes with the RFCS (Section 2.2.8).

The Recirculation Motor Cooling (RMC) Subsystem (Figure 2.1.3) provides forced circulation with an auxiliary combination thrust bearing-impeller mounted on the bottom of the motor rotor, inside the motor housing. The impeller forces cooling water through the motor radial bearings and windings and to the motor cooling heat exchanger. The RMC heat exchangers are located under the RPV close to the RIP motors. The RMC is classified as Quality Group D. For plant availability, the RMC is designed to the same parameters as the RPV.

The RIPs receive power through their individual ASDs from the plant non-essential power system.

As shown in Figure 2.1.3, the RIPs are mounted in the RPV bottom head. The motor cooling heat exchangers are located inside the RPV pedestal adjacent to the RIP motors.

Each RIP instrumentation includes speed, vibration, and RMC temperature transmitters is indicated in the Main Control Room.

In-Service Inspection (ISI) of the motor cover and bolts can be performed during plant shutdown when the motors are removed for routine maintenance.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.1.3 provides a definition of the instructions, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the RRS.

Table 2.1.3: Reactor Recirculation System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. System configuration of the Reactor Recirculation System (RRS) as described in Section 2.1.3 is shown on Figure 2.1.3.	1. Visual field inspections will be conducted of the installed RRS key components identified in Section 2.1.3 and Figure 2.1.3.	1. The installed configuration of the RRS will be considered acceptable if it complies with Figure 2.1.3 and Section 2.1.3.
2. RIPs inertia provide adequate reactor fuel thermal margin during plant transients.	2. Factory measurements will determine the mechanical inertia of the RIP/motor rotating assembly.	2. These inertia measurements confirms RIP inertia in these factory conditions.
3. The reactor coolant pressure boundary (RCPB) motor covers are classified as Quality Group A, Seismic Category 1. The covers and bolts are designed, fabricated, examined, and hydrotested in accordance with the rules of ASME Code Class 1 vessels and are code stamped accordingly.	3. Inspections will be conducted of ASME Code required documents and the Code stamp on the cover and bolts.	3. Existence of necessary ASME Code required documents and the Code stamps on the components confirm that the RCPB cover and bolts are designed, fabricated, and examined as ASME Code Class 1.
4. The RCPB cover and bolts retain their integrity under internal pressure that will be experienced during the service.	4. A hydrostatic test of the RCPB, including the covers and their bolts, will be conducted in accordance with the ASME Code requirements.	4. The hydrostatic test results must conform with the ASME requirements.
5. The materials used for the RCPB motor covers and bolts are proven low and high alloy steels with certain additional requirements for construction, as identified in Section 2.1.1.	5. Inspection will be conducted of the RCPB motor covers and bolts records of materials, fabrication, and examination used in construction of the covers and bolts.	5. Records of the materials and processes must confirm that the requirements specified for the RCPB covers and bolts are satisfied.
6. The RCPB covers and bolts ferritic materials are not susceptible to brittle fracture under pressure during service.	6. Fracture toughness tests of the ferritic materials will be conducted in accordance with the requirements for ASME Class 1 components	6. Records of the fracture toughness data of the RCPB ferritic materials must confirm that the ASME Code requirements are met.
7. The Recirculation Motor Cooling (RMC) forced circulation transfers the heat from each RIP motor to its heat exchanger.	7. Factory or preoperational tests will be performed to determine that the RMC will adequately remove the motor heat within the RMC design limits.	7. Detectors in the RMC Subsystem confirm that the temperatures of the RMC water and motor temperatures are acceptable.

2.2 Control and Instrument

2.2.1 Rod Control and Information System

Design Description

The non-safety design bases of the rod control and information system (RCIS) is to reliably provide:

(1) The capability to control reactor power level by controlling the movement of control rods in reactor core in manual, semiautomated, and automated modes of plant operations.

(2) Controls for some RCIS bypass and surveillance test functions, and summary information of control rods position and status on the RCIS Dedicated Operator Interface (DOI).

(3) Transmission of Fine Motion Control Rod Drives (FMCRD) status and control rods position and status data to other plant systems (e.g., the plant process computer system).

(4) Automatic control rod run-in function of all operable control rods following a scram (scram follow function).

(5) Automatic enforcement of rod movement blocks to prevent potentially undesirable rod movements (these blocks do not have an effect on scram insertion function).

(6) Control capability for insertion of all control rods by an alternate and diverse method [Alternate Rod Insertion (ARI) function].

(7) The capability to enforce a preestablished sequence for control rod movement when reactor power is below the low power setpoint.

(8) The capability to enforce fuel operating thermal limits when reactor power is above the low power setpoint.

(9) The capability to send flow runback signals to Recirculation Flow Control System on detecting an all-rods-in condition.

(10) The capability to provide for Selected Control Rod Run In (SCRRI) function for core thermal-hydraulic stability control.

The RCIS is classified as a Non-Nuclear-Safety (NNS) system, it has a control design basis only, and is not required for the safe and orderly shutdown of the plant. A failure of the RCIS will not result in gross fuel damage. However, the rod block function of RCIS is important in limiting the consequences of a rod withdrawal error, and prevention of local fuel operating thermal limits violations during normal plant operations. Therefore, RCIS is designed to meet single-failure criteria and to be highly reliable.

The RCIS consists of several different types of cabinets (or panels), which contain special electronic/electrical equipment modules, and a dedicated operator interface on the main control panel in the control room. The RCIS block diagram is shown in Figure 2.2.1 which depicts the major components of the RCIS, their interconnections, and interfaces with other ABWR systems.

The RCIS is a dual redundant system that consists of two independent channels for normal control rod position monitoring and control rod movements. The two channels receive the same but separate input signals and perform the same exact functions. For normal functions of RCIS, the two channels must always be in agreement and any disagreement between the two channels results in rod block. However, the protective function logic of RCIS (i.e., rod block) is designed such that the detection of a rod block condition in only one channel of RCIS would result in a rod block.

There are four types of electronic/electrical cabinets that make up the RCIS. They are:

(1) Rod action control cabinets (RACC)

(2) Remote communication cabinets (RCCs)

(3) Fine motion driver cabinets (FMDCs)

(4) Rod brake controller cabinets (RBCCs)

In addition, RCIS includes a fiber-optic dual channel Multiplexing Network that is used for transmission of rod position and status data from RCCs to the RACCs, and rod block/movement command from the RACCs to RCCs. A summary description of each of above is provided below.

(1) Rod Action Control Cabinets (RACC)

There are two RACCs in the control room; RACC Channel A and RACC Channel B that provide for a dual redundant architecture. Each RACC consists of three main functional subsystems, as follows:

(1) Automated Thermal Limit Monitor (ATLM)

(2) Rod Worth Minimizer (RWM)

(3) Rod Action and Position Information (RAPI)

(2) Remote Communication Cabinets (RCC)

The remote communication cabinets (RCCs) contain a dual channel file control module (FCM) and several dual channel rod server modules (RSMs). The FCM interfaces with the RSMs and RAPI.

(3) Fine Motion Driver Cabinets (FMDC)

The fine motion driver cabinets (FMDCs) consist of several stepping motor driver modules. Each stepping motor driver module contains an electronic converter/inverter that converts the incoming 3-phase AC power into DC and then inverts the DC power to variable voltage/frequency AC power that is supplied to FMCRD stepping motors. For each converter/inverter, there exists an Inverter Controller (IC) that controls the duration of power supplied to the stepping motors under the command of RSMs.

(4) Rod Brake Controller Cabinets (RBCC)

The rod brake controller cabinets (RBCCs) contain electrical power supplies, electronic (or relay) logic, and other associated electrical equipment for the proper operation of the FMCRD brakes. Signals for brake disengagement/engagement are received from the associated rod server modules. The brake controller logic provides two separate (channel A and channel B) brake status signals to the associated rod server module.

(5) RCIS Multiplexing Network

The RCIS multiplexing network consists of two independent channels (channel A and channel B) of fiber-optic communication links between the RACCs (channel A and channel B), and the dual channel file control modules located in the remote communication cabinets.

The plant essential multiplexing network interfaces with FMCRD dual redundant separation switches (A/B) and provides the appropriate status signals to the RACC that is used in the RCIS logic for initiating rod block signals if a separation occurs. The essential multiplexing network is not part of the RCIS scope.

(6) RCIS Power Sources

RCIS equipment derive their power from two different sources. Fine Motion Driver Cabinets and Rod Brake Controller Cabinets derive their power from the plant divisional Class 1E power sources that are backed up by plant diesel generators. All other RCIS equipment derive their power from the plant Non-Class 1E uninterruptible AC power system.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.2.1 provides a defin ion of the inspections, tests, and/or analyses; together with associated acceptance criteria, which will be used by RCIS.

Table 2.2.1: Rod Control and Information System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspection, Tests, Analyses	Acceptance Criteria
1. Proper separation is maintained between the non-safety RCIS and safety systems that interface with RCIS.	1. Visual field inspection of installed equipment and review of as-built RCIS and interfacing systems drawings to ensure that implemented isolation methods meet the design requirements.	1. Visual field inspections in conjunction with review of drawings confirm that proper separation is maintained.
2. The RCIS is designed to meet single failure criteria. The two channels of RCIS are independent of each other, in the sense that each channel can independently cause a rod block; and that for normal RCIS functions of control rods movements and control rods position monitoring, the two channels must be in agreement.	2. Preoperational tests will be conducted to confirm channel redundancy, channel protective function independence, and channel agreement for normal RCIS operations.	2. Observation of RCIS continued operation when one channel is disabled, that one channel can cause a rod block, and that it takes the agreement of the two channels to cause normal movement of control rods.
3. RCIS design is capable of continued operation when different subsystems of RCIS are bypassed. RCIS bypass interlock logic precludes a bypass state that would render RCIS inoperational.	3. Preoperational tests will be conducted to confirm RCIS bypass capabilities and to confirm proper functioning of the bypass interlock logic.	3. Observation of RCIS continued operation when different subsystems are bypassed and RCIS bypass interlock logic preventing a bypass state that would violate bypass rules as specified in RCIS design documentation.
4. When reactor power level is below low power setpoint, the Rod Worth Minimizer (RWM) of RCIS enforces control rod withdrawal and insertion sequence to comply with a preestablished pattern, in order to minimize the consequences of a rod drop accident, by issuing a rod movement block signal whenever an out of sequence rod movement is attempted.	4. Preoperational tests of RCIS will include a sufficient number of attempts to withdraw/insert control rods that are both in-compliance and not-in-compliance with the known preestablished pattern, at below and above the low power setpoint.	4. Observation of rod block signals by RWM, when an out sequence rod withdraw/insert is attempted, given that reactor power is below low power setpoint.

Table 2.2.1: Rod Control and Information System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspection, Tests, Analyses	Acceptance Criteria
5. When reactor power is above low power setpoint, the Automated Thermal Limit Monitor (ATLM) of RCIS enforces fuel operating thermal limits (both MCPR and MLHGR) by issuing a rod withdrawal block signal whenever local fuel operating thermal limits are violated.	5. Preoperational tests of RCIS will include sets of simulated LPRM and control rod position data inputs to ATLM to verify that ATLM does generate the proper rod block signal.	5. Observation of rod block signals by ATLM, when ATLM is expected to generate a rod block signal based on input data that simulate a condition of fuel operating thermal limits violation.
6. The Rod Action and Position Information (RAPI) of RCIS, when RCIS is in "Automatic Mode" of operation, automatically withdraws and inserts control rods in compliance with a preestablished rod withdraw/insert sequence, called Reference Rod Pull Sequence (RRPS), under the command of Automatic Power Regulator (APR) system. When RCIS is in "Semiautomatic Mode", RAPI prompts the operator to select and withdraw/insert control rods based on RRPS. When RCIS is in "Manual Mode" the operator can withdraw/insert rods normally. When RCIS is in Semiautomatic Mode or Manual Mode, any attempt by the operator, to withdraw/insert control rods not in compliance with RRPS, RCIS generates an alarm.	6. Preoperational tests of RCIS will include tests to verify that RAPI of RCIS properly and in compliance with RRPS, executes rod withdraw/insert commands from APR in the Automatic Mode. When in Semiautomatic Mode, the RCIS, in compliance with RRPS, correctly prompts the operator to the selection of control rods. And that, when RCIS is in Manual Mode, control rods can be withdrawn/inserted in a normal fashion. When in Semiautomatic or Manual Mode, RCIS generates an alarm when a rod movement that does not comply with RRPS is attempted.	6. Observation of RCIS proper operation in the Automatic Mode such that adherence to RRPS is maintained and that in the Semiautomatic Mode, RCIS, in compliance with RRPS, correctly prompts the operator, and that RCIS generates an Alarm when the operator attempts to withdraw/insert an out of sequence control rod either in Semiautomatic or Manual Mode.
7. On receipt of Selected Control Rod Run In (SCRRI) signal from the Recirculation Flow Control System (RFCS), RCIS, automatically, inserts a predetermined number of control rods to a predetermined position for each control rod.	7. Preoperational tests of RCIS will include a test where simulated SCRRI signals from RFCS will be transmitted to RCIS to verify that RCIS correctly inserts SCRRI rods to their SCRRI target positions.	7. Observation of correct execution of SCRRI command from RFCS.

Table 2.2.1: Rod Control and Information System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspection, Tests, Analyses	Acceptance Criteria
8. On receipt of Scram Follow signal from Reactor Protection System (RPS), RCIS, automatically, runs-in all operable control rods.	8. Preoperational tests of RCIS will include a test to verify that RCIS does execute the automatic run-in of all operable control rods, following the receipt of simulated scram follow signal from RPS.	8. Observation of correct execution of scram follow command from RPS (i.e, automatic run-in of all rods).
9. RCIS, on receipt of an alternate rods in (ARI) command from RFCS, automatically inserts all operable control rods to their full-in position.	9. Preoperational tests of RCIS will include a test to verify that RCIS does execute the automatic run-in of all operable control rods following the receipt of simulated ARI command from RFCS.	9. Observation of correct execution of ARI command from RFCS (i.e., automatic run-in of all rods).
10. RCIS, on receipt of an all-rods-in (either Scram Follow or ARI) command generates "Run Back" signals that are sent to the Adjustable Speed Drives (ASD) of RFCS.	10 Preoperational test of RCIS will include a test to verify that RCIS does generate the proper Run Back signals following the receipt of a simulated all-rods-in command.	10. Observation of proper generation of "Run Back" signals by RCIS, following the receipt of an all-rods-in command by RCIS.

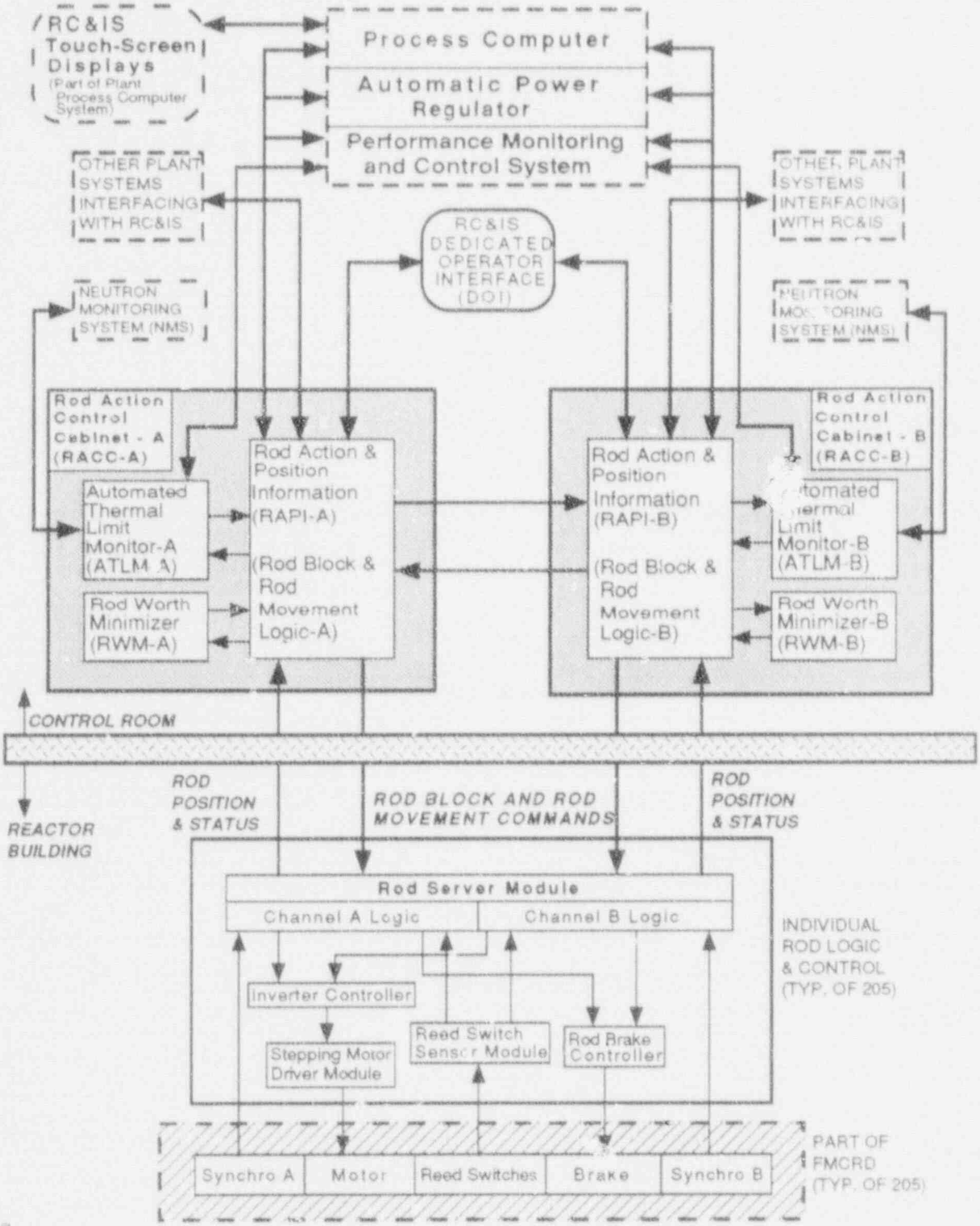


FIGURE 2.2.1: ABWR ROD CONTROL AND INFORMATION SYSTEM BLOCK DIAGRAM

Figure 2.1.3 Control and Instrument

2.2.2 Control Rod Drive System

Design Description

The Control Rod Drive (CRD) System is composed of three major elements: (1) the electro-hydraulic fine motion control rod drive (FMCRD) mechanisms, (2) the hydraulic control unit (HCU) assemblies, and (3) the Control Rod Drive Hydraulic (CRDH) Subsystem. The FMCRDs provide electric-motor-driven positioning for normal insertion and withdrawal of the control rods and hydraulic-powered rapid control rod insertion (scram) for abnormal operating conditions. Simultaneous with scram, the FMCRDs also provide electric-motor driven run-in of all control rods as a path to rod insertion that is diverse from the hydraulic-powered scram. The hydraulic power required for scram is provided by high pressure water stored in the individual HCUs. Each HCU is designed to scram two FMCRDs. The HCUs also provide the flow path for purge water to the associated drives during normal operation. The CRDH Subsystem supplies high pressure demineralized water which is regulated and distributed to provide charging of the HCU scram accumulators and purge water flow to the FMCRDs.

During power operation, the CRD System controls changes in core reactivity by movement and positioning of the neutron absorbing control rods within the core in fine increments via the FMCRD electric motors, which are operated in response to control signals from the Rod Control and Information System (RCIS).

The CRD System provides rapid control rod insertion (scram) in response to manual or automatic signals from the Reactor Protection System (RPS), so that no fuel damage results from any plant transient.

There are 205 FMCRDs mounted in housings welded into the reactor vessel bottom head. A schematic of the drive is shown in Figure 2.2.2.a. Each FMCRD has a movable hollow piston tube that is coupled at its upper end, inside the reactor vessel, to the bottom of a control rod. The piston is designed such that it can be moved up or down, both in fine increments and continuously over its entire range, by a ball nut and ball screw driven at a nominal speed of 30 mm/sec by the electric stepper motor. In response to a scram signal, the piston rapidly inserts the control rod into the core hydraulically using stored energy in the HCU scram accumulator. The scram water is introduced into the drive through a scram inlet connection on the FMCRD housing, and is then discharged directly into the reactor vessel via clearances between FMCRD parts. The FMCRD scram time requirements with the reactor pressure as measured at the vessel bottom below 1085 psig are:

Percent Insertion	Time (sec)
10	≤ 0.42
40	≤ 1.00

Percent Insertion	Time (sec)
60	≤ 1.44
100	≤ 2.80

The FMCRD design includes an electro-mechanical brake on the motor drive shaft and a ball check valve at the point of connection with the scram inlet line. These features prevent control rod ejection in the event of a failure of the scram insert line. An internal housing support is provided to prevent ejection of the FMCRD and its attached control rod in the event of a housing failure. It utilizes the outer tube of the drive to provide support. The outer tube, which is welded to the drive middle flange, attaches by a bayonet lock to the control rod guide tube (CRGT) base. The CGRT, being supported by the lower core plate, in turn, prevents any downward movement of the drive.

The FMCRD is designed to detect separation of the control rod from the drive mechanism. Two redundant and separate Class 1E switches detect separation of either the control rod from the hollow piston or the hollow piston from the ball nut. Actuation of either switch will cause an immediate rod block and initiate an alarm in the control room, thereby preventing the occurrence of a rod drop accident.

There are 103 HCUs, each of which provides sufficient volume of water stored at high pressure in a pre-charged accumulator to scram two FMCRDs at any reactor pressure. Figure 2.2.2.b shows the major HCU components. Each accumulator is connected to its associated FMCRDs by a hydraulic line that includes a normally-closed scram valve. The scram valve opens by spring action but is normally held closed by pressurized control air. To cause scram, the RPS provides a de-energizing reactor trip signal to the solenoid-operated pilot valve that vents the control air from the scram valve. The system is 'fail safe' in that loss of either electrical power to the solenoid pilot valve or loss of control pressure causes scram. The HCUs are housed in the secondary containment at the basemat elevation. This is a Seismic Category I structure, and the HCUs are protected from external natural phenomena such as earthquakes, tornados, hurricanes and floods, as well as from internal postulated accident phenomena. In this area, the HCUs are not subject to conditions such as missiles, pipe whip, and discharging fluids.

The CRDH Subsystem design provides the pumps, valves, filters, instrumentation, and piping to supply the high pressure water for charging the HCUs and purging the FMCRDs. Figure 2.2.2.b shows the major system equipment. Two 100% capacity pumps (one on standby) supply the HCUs with water from the condensate treatment system and/or condensate storage tank for charging the accumulators and for supplying FMCRD purge water. The CRDH Subsystem equipment is housed in the Seismic Category I reactor building to protect the system from floods, tornadoes, and other natural phenomena.

The CRD System includes control room indication and alarms to allow for monitoring and control during design basis operational conditions, including system flows, temperatures and pressures, as well as valve position indication and pump on/off status for those instruments and components shown in Figure 2.2.2.b, with the exception of simple check valves. Class 1E pressure instrumentation is provided on the HCU charging water header to monitor header performance. The pressure signals from this instrumentation are provided to the RPS, which will initiate a scram if the header pressure degrades to a predetermined low pressure setpoint. This feature assures the capability to scram and safely shut down the reactor before HCU accumulator pressure can degrade to the level where scram performance is adversely affected following the loss of charging header pressure.

The FMCRD electric motors are powered from a dedicated non-divisional 480 VAC power center fed by the Division I 6.9-kV Class 1E bus as the first source of standby power and by the non-divisional combustion turbine generator as the second backup source.

The CRD pumps, valves, and controls are powered from two separate trains of 6.9-kV offsite power with automatic transfer to the combustion turbine generator upon loss of preferred power.

Components of the system that are required for scram (FMCRDs, HCUs and scram piping), are classified Seismic Category I. The balance of the system equipment (pumps, valves, filters, piping, etc.) is classified as non-Seismic Category I, with the exception of the Class 1E charging water header pressure instrumentation, which is Seismic Category I. The major mechanical components are designed to meet ASME Code requirements as shown below:

	ASME	Design Conditions	
Component	**Code Class**	**Pressure**	**Temperature**
FMCRD (RCPB parts)	1	87.9 kg/cm^{2}g	302°C
Scram Piping	2	190 kg/cm^{2}g	66°C
HCU (scram related parts)	2	190 kg/cm^{2}g	66°C
CRD Pumps	non-Code	190 kg/cm^{2}g	66°C
CRDHS Piping, Valves	non-Code	190 kg/cm^{2}g	66°C

The CRD System is separated both physically and electrically from the Standby Liquid Control (SLC) System.

Inspections, Tests, Analyses and Acceptance Criteria

This section provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the CRD System.

Table 2.2.2: Control Rod Drive System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. A simplified configuration of the Control Rod Drive (CRD) System as described in Section 2.2.2 is shown in Figure 2.2.2.b.	1. Visual field inspections will be conducted to confirm that the installed CRD System equipment is in compliance with the design configuration defined in Figure 2.2.2.b.	1. The system configuration is in accordance with Figure 2.2.2.b.
2. The RCPB portions of the FMCRD (middle flange, spool piece, mounting bolts, seal housing) are classified as ASME Code Class 1. They are designed, fabricated, examined, and hydrotested per the rules of ASME Code, Section III.	2. Inspections will be conducted of ASME Code required documents and the Code stamp on the actual components to verify that they have been manufactured per the relevant ASME requirements.	2. The components have appropriate ASME Code, Section III, Class 1 certifications and Code stamps.
3. The scram-related parts of the HCU and the scram piping are classified as ASME Code Class 2. They are designed, fabricated, examined, and hydrotested per the rules of ASME Code, Section III.	3. Inspections will be conducted of ASME Code required documents and the Code stamp on the actual components to verify that they have been manufactured per the relevant ASME requirements.	3. The components have appropriate ASME Code, Section III, Class 2 certifications and Code stamps.
4. The installed FMCRDs and HCUs shall be capable of providing control rod scram time performance within specified limits.	4. Scram tests will be conducted during the preoperational testing program to confirm proper operation of HCUs and associated valves, including scram timing demonstrations with the reactor at atmospheric pressure.	4. The observed/measured scram times are: Percent Insertion Time(sec) 10 ≤ 0.42 40 ≤ 1.00 60≤ 1.44 100 ≤ 2.80
5. The nominal FMCRD motor-driven rod motion speed shall be 30 mm/sec.	5. Functional tests will be performed for each FMCRD during the preoperational testing program to confirm that drive speed complies with the design commitment.	5. The observed/measured motor-driven FMCRD speed is 30 mm/sec ±10%.
6. The FMCRD electromechanical brake and ball check valve shall be capable of performing their rod ejection prevention functions as identified in Section 2.2.2.	6. Functional tests of the brake and check valve will be performed for each FMCRD during the preoperational testing program.	6. The brake holding torque is within specified limits. The ball check valve actuates to seal the scram inlet port under conditions of reverse flow.

Table 2.2.2: Control Rod Drive System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. The FMCRD outer tube, which is welded to the drive middle flange, shall bayonet lock to the CGRT base to form the internal housing support for prevention of rod ejection in the event of a CRD housing failure.	7. Visual inspection of the actual installed equipment shall confirm the FMCRD is in compliance with the design commitment.	7. Inspection confirms that a bayonet lock is provided.
8. The FMCRD separation switches shall detect separation of the control rod from the drive mechanism and initiate a control room alarm. The separation switches are classified Class 1E.	8. The separation switch operation shall be tested as part of the drive functional testing conducted during the preoperational testing program.	8. The switches actuate the control room alarm when exercised.
9. The pressure instrumentation on the HCU charging water header for monitoring HCU accumulator charging pressure shall signal the RPS to initiate a scram if charging pressure is low.	9. Logic and instrument functional testing shall be performed to demonstrate that low charging header pressure will generate a scram by the RPS.	9. The pressure instrumentation functions as required to generate low pressure scram signals to the RPS.
10. CRD System equipment can be powered from the standby AC power supplies as described in Section 2.2.2.	10. System tests will be conducted after installation to confirm that the electrical power supply configurations are in compliance with design commitments.	10. The installed equipment can be powered from standby AC power supplies.

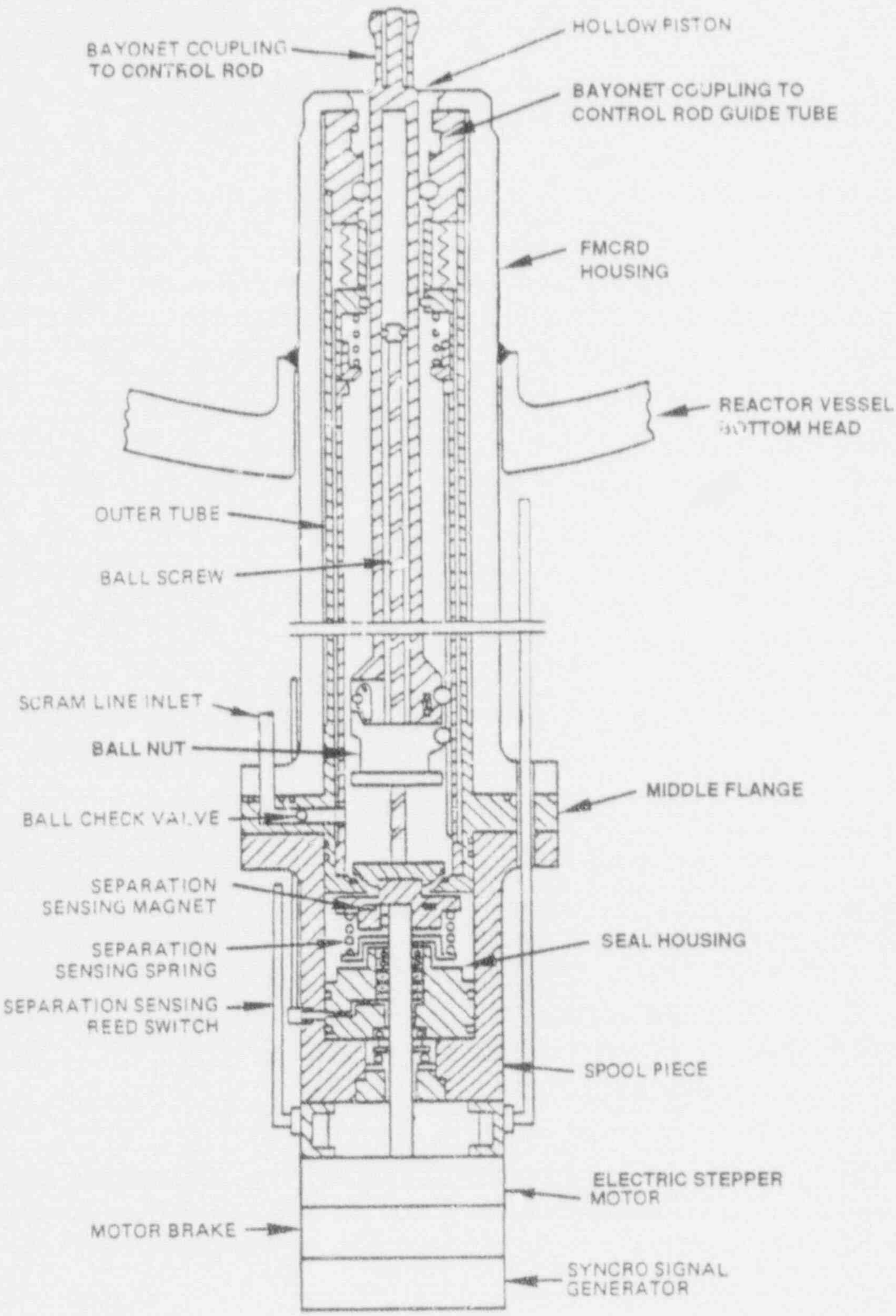


Figure 2.2.2a Fine Motion Control Rod Drive Schematic

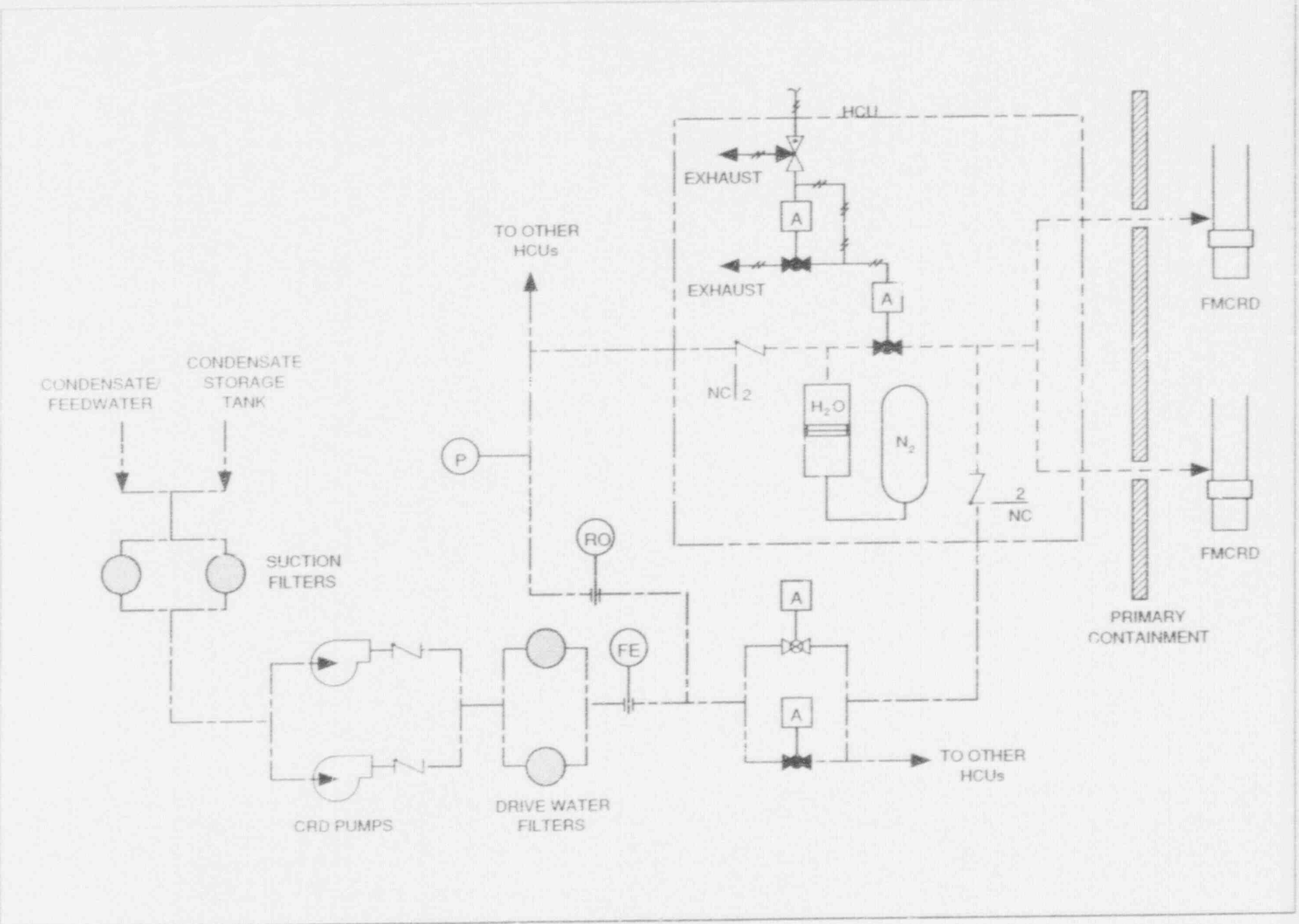


Figure 2.2.2b Control Rod Drive System

2.2.3 Feedwater Control System

Design Description

The Feedwater Control (FDWC) System controls the flow of feedwater into the reactor pressure vessel (RPV) to maintain the water level in the vessel within predetermined limits during all plant operating modes. The FDWC System may operate in either single- or three-element control modes. At low reactor powers (when steam flow is either negligible or else measurement is below scale), the FDWC System utilizes only water level measurement in single-element control mode. When steam flow is negligible, the Reactor Water Cleanup (CUW) System dump valve flow can be controlled by the FDWC System in single-element mode in order to counter the effects of density changes during heatup and purge flows into the reactor. At higher powers, the FDWC System in three-element control mode uses water level, main steamline flow, main feedwater line flow, and feedpump suction flow measurements for water level control. The FDWC System control structure is shown in Figure 2.2.3.

The FDWC System is a power generation (control) system with operation range between high water level and low water level trip setpoints. It is classified as nonsafety-related. This system is not required for safety purposes, nor is it required to operate after the design basis accident. This system is also required to operate in the normal plant environment for power generation purposes only.

Reactor vessel narrow range water level is measured by three identical, independent sensing systems. For each level measurement channel, a differential pressure transmitter senses the difference between the pressure caused by a constant reference column of water and the pressure caused by the variable height of water in the reactor vessel. The FDWC fault tolerant digital controllers (FTDCs) will determine one validated narrow range level signal using the three level measurements as inputs to a signal validation algorithm. The validated narrow range water level is indicated on the main control panel and is continuously recorded in the main control room.

The steam flow in each of four main steamlines is sensed at the RPV nozzle venturi's. The Multiplexing (MUX) System signal conditioning algorithms process the venturi differential pressures and provide steam flow rate signals to the FTDCs for validation. These validated measurements are summed in the FTDCs to give the total steam flow rate out of the vessel. The total steam flow rate is indicated on the main control panel and recorded in the main control room.

Feedwater flow is sensed at a single flow element in each of the two feedwater lines. The MUX System signal conditioning algorithms process the flow element differential pressure and provide feedwater flow rate signals to the FTDCs. These validated measurements are summed in the FTDCs to give the total feedwater flow rate into the vessel. The total feedwater flow rate is indicated on the main control panel and recorded in the main control room.

Feedpump suction flow is sensed at a single flow element upstream of each feedpump. The MUX System signal conditioning algorithms process the flow element differential pressure and provide the suction flow rate measurements to the FTDCs. The feedpump suction flow rate is compared to the demand flow for that pump, and the resulting error is used to adjust the actuator in the direction necessary to reduce that error. Feedpump speed change and low flow control valve position control are the flow adjustment techniques involved.

Three modes of feedwater flow control (and, thus, level control) are provided: (1) single-element control; (2) three-element control; and (3) manual control. Each FTDC will execute the control software for all three of the control modes. Actuator demands from the redundant FTDCs will be sent over the MUX System to field voters which will determine a single demand to be sent to each actuator. Each feedpump speed or control valve position demand may be controlled either automatically by the control algorithms in the FTDCs or manually from the main control panel through the FTDCs.

Three-element automatic control is provided for normal operation. Three-element control utilizes water level, feedwater flow, steam flow, and feedpump flow signals to determine the feedpump demands. The total feedwater flow is subtracted from the total steam flow signal, yielding the vessel flow mismatch. The flow mismatch, summed with the conditioned level error from the master level controller, provides the demand for the master flow controller. The master flow controller output provides the demand for the feedpump flow loops which send a pump speed demand signal to the adjustable speed drives (ASD) for the feedpump.

In the single-element control mode, which is employed at lower feedwater flow rates, only conditioned level error is used to determine the feedpump demand. The master level controller conditions the level error and sends it directly to the feedpump ASDs, and/or low flow control valve actuator. When the reactor water inventory must be decreased (e.g., during very low steam flow rate conditions), the CUW System dump valve is controlled by the FDWC system in single-element control. Reactor water is dumped through the CUW System to the condenser.

Each feedpump flow control actuator can be controlled 'manually' from the main control panel by selecting the manual mode for that feedpump. In manual mode, the operator may increase or decrease the demand that is sent directly to the ASD of the chosen feedpump.

The FDWC System also provides interlocks and control functions to other systems. When the reactor water level reaches the high level trip setpoint, the

FDWC system simultaneously annunciates a control room alarm, sends a trip signal to the turbine control system to trip the turbine generator, sends trip signals to all feedpumps, and closes the main feedwater discharge valves. This interlock is enacted to protect the turbine from damage from high moisture content in the steam caused by excessive carryover, while preventing water level from rising any higher.

The FDWC System will send a signal to the main steamline condensate drain valves to open when steam flow rate is below a pre-determined setpoint. This also protects the turbine from damage caused by excessive moisture in the steamline.

The FDWC System will send a trip signal to the Recirculation Flow Control (RFC) System when reactor water level reaches this low level setpoint. The RFC System will runback the reactor internal pumps (RIPs) if this low level signal coincides with a feedpump trip signal provided to the RFC System by the Feedwater and Condensate System. The RIP runback will aid in avoiding a low water level scram by reducing the reactor steaming rate.

Feedwater flow is delivered to the reactor vessel through a combination of three adjustable speed turbine-driven feedpumps and a low flow control valve. Each adjustable speed drive can also be controlled by its manual/automatic transfer station, which is part of the Feedwater and Condensate System. A Low Flow Control Valve (LFCV) is also provided in parallel to a common discharge line from the feedpumps. The LFCV can also be controlled by the manual/automatic transfer station which is part of the Feedwater and Condensate System.

The FDWC System is not required for safety purposes, nor is it required to operate after the design basis accident. This system is required to operate in the normal plant environment for power generation purposes only.

The FDWC System is powered by redundant uninterruptable power supplies (UPS). No single power failure will result in the loss of any FDWC System functions.

Controllers to be used for the FDWC System shall be triplicated, fault tolerant digital type with self-test and diagnostic capabilities.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.2.3 provides definition of the inspection, tests, and/or analysis, together with associated acceptance criteria which will be undertaken for the Feedwater Control System.

Table 2.2.3: Feedwater Control System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. This system automatically maintains reactor water level within operational limits, by regulating feedwater flow and reactor water cleanup system dump flow. This system shall use single-element control (level only), or three-element control (level, steam flow and feedwater flow), or manual control.	1. Perform tests to confirm that the system can maintain reactor water level in all control modes. Operate system in each mode of controls: – Single Element – Three Element – Manual	1. The FDWC System must maintain water level between high and low trip setpoints (see Figure 2.2.3).
2. This system must be powered by redundant uninterruptable power supplies.	2. Loss of power tests shall demonstrate no loss in FDWC System function.	2. There is no loss of FDWC System function by loss of any power supply.
3. The water level shall be measured by three identical, independent sensing systems.	3. Inspection and testing will show the three identical and independent sensing systems.	3. The FDWC System conforms to Figure 2.2.3, and the input signal is independent of the output signal response.
4. Triplicated, fault tolerant digital controllers (FTDCs) with self test and diagnostic capabilities shall be used.	4. Inspect FTDCs and perform validation testing.	4. The FTDC, self-test and on-line diagnostics test features are capable of identifying and isolating failures of process sensors, I/O cards, buses, power supplies, processors and inter-processors communication paths down to the machine level.
5. The RP System shall monitor reactor water level and in the event that high water level is reached, shall issue trip signals to the Turbine Control System to trip turbine generator, Feedwater and Condensate Systems to trip feedpumps and close discharge valves.	5. Perform test to confirm that the high water level trip signal is properly issued.	5. High water level trip signal is issued to the Turbine Control System and Feedwater and Condensate System when reactor water reaches high level.
6. This system shall monitor reactor water level and, in the event that low water level is reached, shall issue trip signal to Recirculation Flow Control System (RFC System logic determines need for RIP runback).	6. Perform test to confirm that the low water level trip signal is properly issued.	6. Low level trip signal is issued to the Recirculation Flow Control System when reactor water reaches low level.

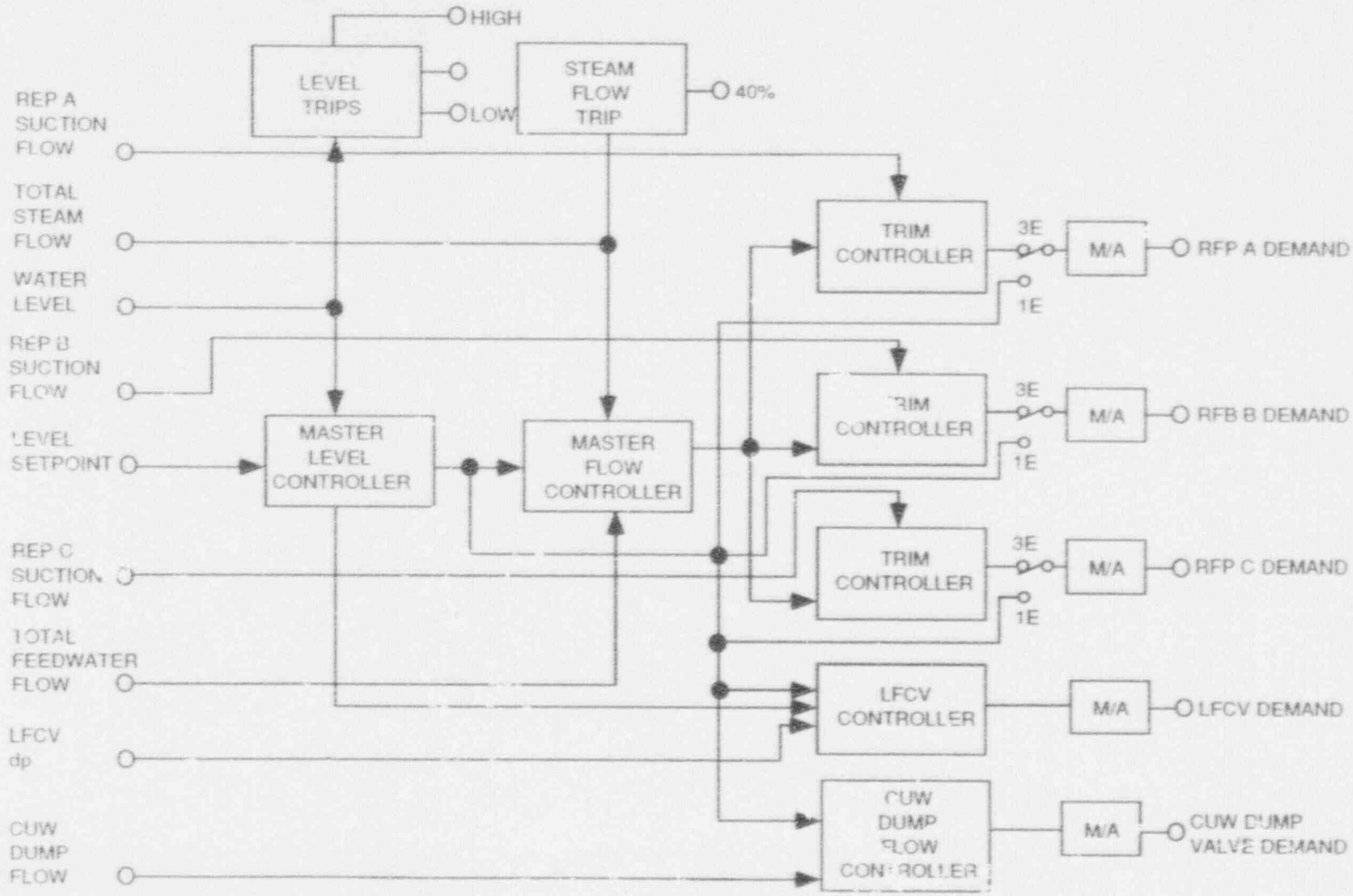


Figure 2.2.3a FWC Control Algorithm

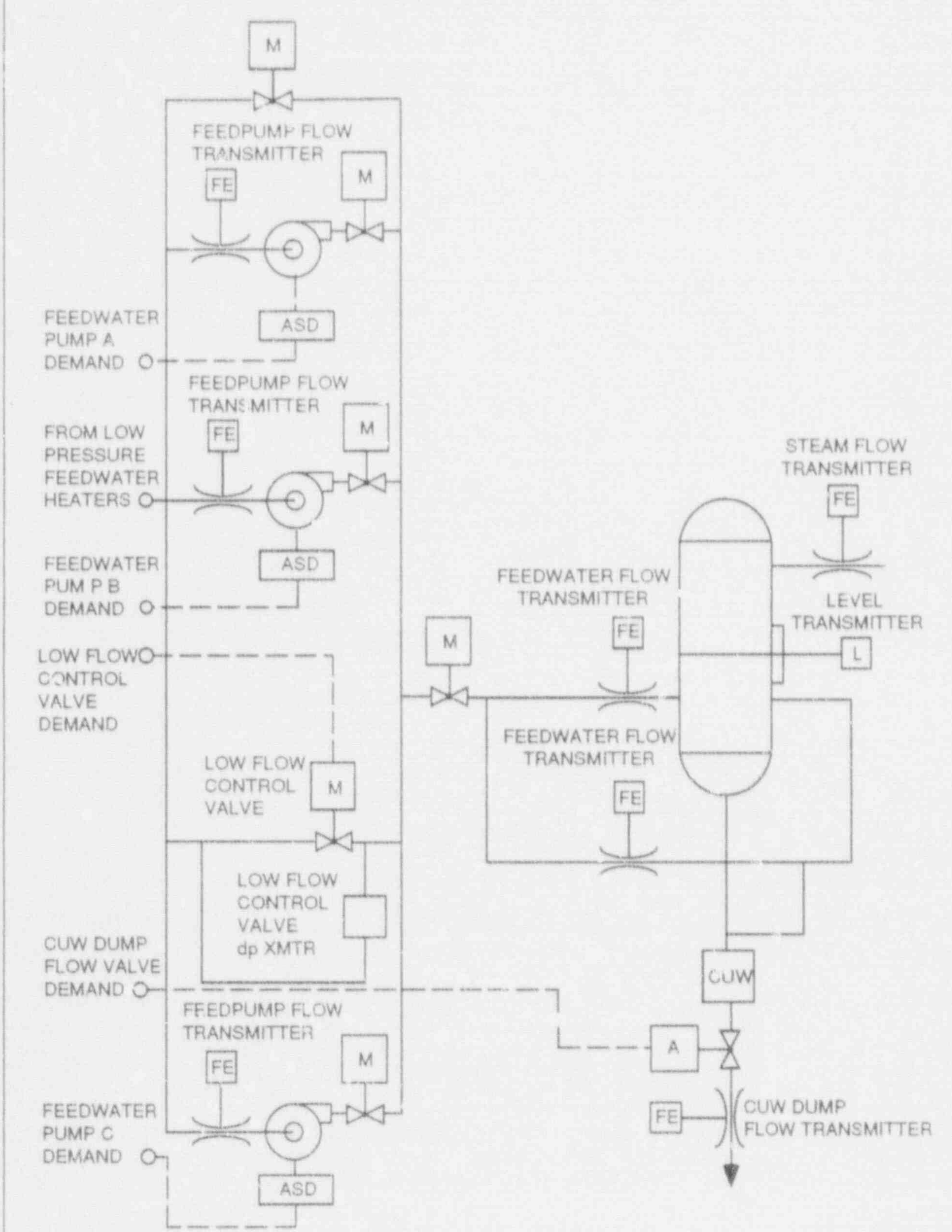


Figure 2.2.3b FWC Piping and Instrumentation

2.2.4 Standby Liquid Control System

The Standby Liquid Control (SLC) System is designed to inject neutron absorbing poison using a boron solution into the reactor and thus provide back-up reactor shutdown capability independent of the normal reactivity control system based on insertion of control rods into the core. The SLC System is capable of operation over a wide range of reactor pressure conditions up to and including the elevated pressures associated with an anticipated plant transient coupled with a failure to scram (ATWS).

The SLC System is designed to bring the reactor, at any time in a cycle, and at all conditions, from full power to a subcritical condition, with the reactor in the most reactive xenon-free state, without control rod movement. The system will inject the minimum required boron solution in 61 minutes.

The SLC System (Figure 2.2.4) consists of a boron solution storage tank, two positive displacement pumps, two motor-operated injection valves which are provided in parallel for redundancy, and associated piping and valves used to transfer borated water from the storage tank to the reactor pressure vessel (RPV). The borated solution is discharged through the 'B' high pressure core flooder (HPCF) subsystem sparger. Key equipment performance requirements are:

(1)	Pump flow (minimum)	100 gpm with both pumps running
(2)	Maximum reactor pressure (for injection)	1250 psig
(3)	Pumpable volume in storage tank (minimum)	6100 U.S. gal

The required volume of solution contained in the storage tank is dependent upon the solution concentration, and this concentration can vary during reactor operations. A required boron solution volume/concentration relationship is used to define acceptable SLC System storage tank conditions during plant operation.

The SLC System is automatically initiated during an ATWS. An ATWS condition exists when either of the following occurs:

(1) High RPV pressure (1125 psig) and Average Power Range Monitor (APRM) not down scale for 3 minutes, or

(2) Low RPV level (Level 2) and APRM not down scale for 3 minutes.

When the SLC System is automatically initiated to inject a liquid neutron absorber into the reactor, the following devices are actuated:

(1) The two injection valves are opened.

(2) The two storage tank discharge valves are opened.

(3) The two injection pumps are started.

(4) The reactor water cleanup isolation valves are closed.

The SLC System can also be manually initiated from the main control room. When it is manually initiated to inject a liquid neutron absorber into the reactor, the following devices are actuated by each switch:

(1) One of the two injection valves is opened.

(2) One of the two storage tank discharge valves is opened.

(3) One of the two injection pumps is started.

(4) One of the reactor water cleanup isolation valves is closed.

The SLC System provides borated water to the reactor core to compensate for the various reactivity effects during the required conditions. These effects include xenon decay, elimination of steam voids, changing water density due to the reduction in water temperature, Doppler effect in uranium, changes in neutron leakage, and changes in control rod worth as boron affects neutron migration length. To meet this objective, it is necessary to inject a quantity of boron which produces a minimum concentration of 850 ppm of natural boron in the reactor core at 70°F. To allow for potential leakage and imperfect mixing in the reactor system, an additional 25% (220) is added to the above requirement. The required concentration is thus achieved, accounting for dilution in the RPV with normal water level and including the volume in the RHR shutdown cooling piping. This quantity of boron solution is the amount which is above the pump suction shutoff level in the tank, thus allowing for the portion of the tank volume which cannot be injected.

The pumps are capable of producing discharge pressure to inject the solution into the reactor when the reactor is at high pressure conditions corresponding to the system relief valve actuation (1560 psig), which is above peak ATWS pressure.

The SLC System includes sufficient control room indication to allow for the necessary monitoring and control during design basis operational conditions. This includes pump discharge pressure, storage tank liquid level and temperature, as well as valve open/close and pump on/off indication for those components shown on Figure 2.2.4 (with the exception of the simple check valves).

The SLC System uses a dissolved solution of sodium pentaborate as the neutron-absorbing poison. This solution is held in a storage tank which has a heater to maintain solution temperature above the saturation temperature. The heater is capable of automatic operation and automatic shutoff to maintain an acceptable solution temperature. The SLC System solution tank, a test water tank, the two positive displacement pumps, and associated valving are all located in the secondary containment on the floor elevation below the operating floor. This is a Seismic Category I structure, and the SLC System equipment is protected from phenomena such as earthquakes, tornados, hurricanes, and floods, as well as from internal postulated accident phenomena. In this area, the SLC System is not subject to conditions such as missiles, pipe whip, and discharging fluids.

The pumps, heater, valves, and controls are powered from the standby power supply or normal offsite power. The pumps and valves are powered and controlled from separate buses and circuits so that single active failure will not prevent system operation. The power supplied to one motor-operated injection valve, storage tank discharge valve, and injection pump is powered from Division I, 48 VAC. The power supply to the other motor-operated injection valve, storage tank outlet valve, and injection pump is powered from Division II, 480 VAC. The power supply to the tank heaters and heater controls is connectable to a standby power source. The standby power source is Class 1E from an on-site source and is independent of the off-site power.

Components of the SLC System which are required for injection of the neutron absorber into the reactor are classified Seismic Category I. The major mechanical components are designed to meet ASME Code requirements as shown below:

Component	ASME Code Class	Design Conditions Pressure	Design Conditions Temperature
Storage Tank	2	Static Head	150°F
Pump	2	1560 psig	150°F
Injection Valves	1	1560 psig	150°F
Piping Inboard of Injection Valves	1	1250 psig	575°F

Piping and components not required for the injection of the neutron absorber (e.g., test tank, sampling system line, and storage tank vent) are classified Non-Nuclear Safety (NNS).

Design provisions to permit system testing include a test tank and associated piping and valves. The tank can be supplied with demineralized water which can be pumped in a closed loop through either pump or injected into the reactor.

The SLC System is separated both physically and electrically from the Control Rod Drive System.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.2.4 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria, which will be undertaken for the SLC System.

Table 2.2.4: Standby Liquid Control System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The minimum average poison concentration in the reactor after operation of the SLC System shall be equal to or greater than 850 ppm.	1. Construction records, revisions and plant visual examinations will be undertaken to assess as-built parameters listed below for compatibility with SLC System design calculations. If necessary, an as-built SLC System analysis will be conducted to demonstrate that the acceptance criteria are met. **Critical Parameters:** a. Storage tank pumpable volume b. RPV water inventory at 70°F c. RHR shutdown cooling system water inventory at 70°F	1. It must be shown the SLC System can achieve a poison concentration of 850 ppm or greater, assuming a 25% dilution due to non-uniform mixing in the reactor and accounting for dilution in the RHR shutdown cooling systems. This concentration must be achieved under system design basis conditions. This requires that the SLC System meet the following values: a. Storage tank pumpable volume range 6100-6800 gal. b. RPV water inventory $\leq 1.00 \times 10^6$ lb c. RHR shutdown cooling system inventory $\leq 0.287 \times 10^6$ lb
2. A simplified system configuration is shown in Figure 2.2.4.	2. Inspections of installation records, together with plant walkdowns, will be conducted to confirm that the installed equipment is in compliance with the design configuration defined in Figure 2.2.4.	2. The system configuration is in accordance with Figure 2.2.4.

Table 2.2.4: Standby Liquid Control System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3. The SLC System shall be capable of delivering 100 gpm of solution with both pumps operating against the elevated pressure conditions which can exist in the reactor during events involving SLC System initiation.	3. System preoperation tests will be conducted to demonstrate acceptable pump and system performance. These tests will involve establishing test conditions that simulate conditions which will exist during an SLC System design basis event. To demonstrate adequate Net Positive Suction Head (NPSH), delivery of rated flow will be confirmed by tests conducted at conditions of low level and maximum temperature in the storage tank, and the water will be injected from the storage tank to the RPV.	3. It must be shown that the SLC System can automatically inject 100 gpm (both pumps running) against a reactor pressure of 1250 psig with simulated ATWS conditions. It must also be shown that the SLC System pumps can pump the entire storage tank pumpable volume.
4. The system is designed to permit in-service functional testing of the SLC System.	4. Field tests will be conducted after system installation to confirm that in-service system testing can be performed.	4. Using normally installed controls, power supplies and other auxiliaries, the system has the capability to perform: a. Pump tests in a closed loop on the test tank. b. RPV injection tests using demineralized water from the test tank.
5. The pump, heater, valves and controls can be powered from the standby AC power supply as described in Section 2.2.4.	5. System tests will be conducted after installation to confirm that the electrical power supply configurations are in compliance with design commitments.	5. The installed equipment can be powered from the standby AC power supply.
6. SLC System components which are required for the injection of the neutron absorber into the reactor are classified Seismic Category I and qualified for appropriate environment for locations where installed.	6. See Generic Equipment Qualification verification activities (ITA).	6. See Generic Equipment Qualification Acceptance Criteria (AC).

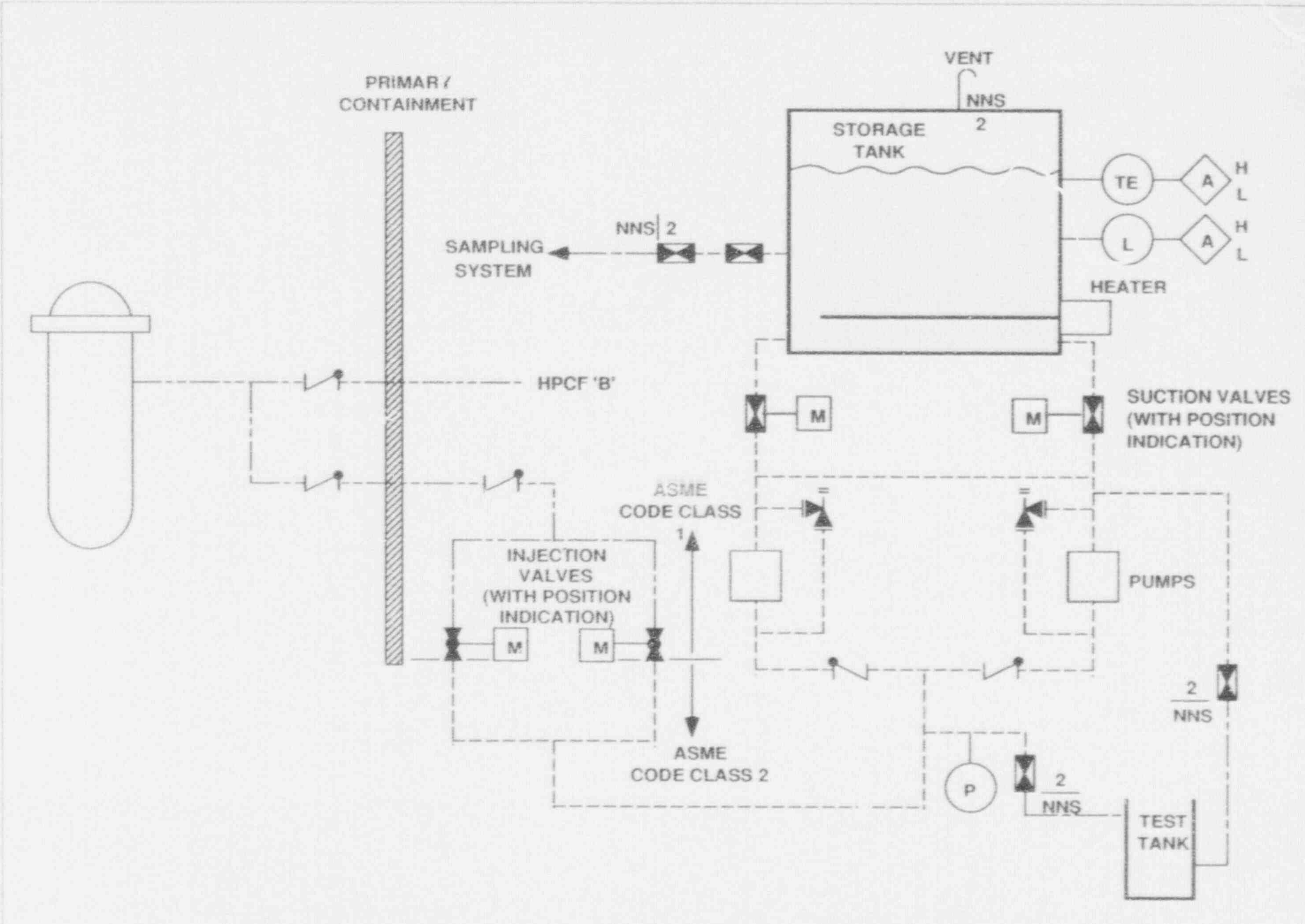


Figure 2.2.4 Standby Liquid Control System (Standby Mode)

2.2.5 Neutron Monitoring System

Design Description

The neutron monitoring system (NMS) for the Advanced Boiling Water Re... .or (ABWR) is a neutron monitoring and protection system. The primary functions of the system are to: (1) monitor the thermal neutron flux in the reactor core as reactor power information, (2) provide trip signals to the reactor protection system to initiate reactor scram under excessive neutron flux (and thermal power) increase condition or neutron flux fast rising condition, and (3) provide power information to the operator and other plant control or process systems.

The NMS is classified as a safety related system. The safety related subsystems of the NMS consist of the startup range neutron monitor (SRNM), the local power range monit .r (LPRM), and the average power range monitor (APRM). The LPRM and the APRM together are also called power range neutron monitor (PRNM). The non-safety related subsystems consist of the automated traversing in-core probe (ATIP) system and the multi-channel rod block monitor (MRBM) system. The NMS detectors and the safety related electrical equipments of the system are classified as Safety Class 2 and 3, Seismic Category I, an.l as IEEE electrical category Class 1E.

The SRNM monitors neutron flux from the source range (1×10^3 nv) to approximately 15% of the rated power. The SRNM subsystem has ten SRNM channels which are evenly distributed throughout the reactor core and assigned to four safety divisions. The SRNM detector is a fixed in-core fission chamber sensor. Detector cables are separated according to different divisional assignment, connected to their designated pre-amplifiers located in the reactor building, and then transmitted to signal processing electroni . nits. The SRNM can generate a high neutron flux trip or a short period trip s.g. al to initiate scram in time to prevent fuel damage resulting from anticipa. .d or abnormal operational transients. Trip signal outputs from the SRNM channels are divided and assigned to four safety divisions. Any single SRNM channel trip will cause a trip in this safety division. The SRNM channels are grouped into three bypass groups independent of their safety division assignment. Individual SRNM channel can be bypassed to allow maintenance. Bypassed SRNM will not cause the trip signal to be sent to the RPS.

The LPRM monitors local neutron flux in the power range from 1% to 125% of the rated power, which overlaps with the SRNM monitoring range from 1% to at least 10% of the rated power. There are fifty-two LPRM detector assemblies evenly distributed in the core, with four sensors per each LPRM assembly. The LPRM detector is a fixed in-core fission chamber sensor. The LPRM assembly also contains a calibration tube for the ATIP detector to traverse. The LPRM detector outputs are connected to the APRM signal conditioning units, where the signals are processed and amplified. All LPRM detector signals are divided and assigned to four APRM channels corresponding to the four safety divisions. Signals in each channel are summed and averaged to form an APRM signal. The APRM is then calibrated to represent the core average power. The APRM can generate a high neutron flux trip, a simulated thermal power trip signal, or a rapid flow decrease trip signal, to initiate scram in time to prevent fuel damage resulting from anticipated or abnormal operational conditions. Any two APRM trips out of the four APRM channels will initiate a reactor scram trip in the RPS. A bypassed APRM channel will not cause a trip output sent to the RPS. One APRM channel can be bypassed at any one time. Consequently, for both the SRNM and the APRM, the redundancy criteria are met such that in the event of a single failure under permissible SRNM or APRM bypass conditions, safety protection function can still be performed. A typical NMS division block diagram is shown in Figure 2.2.5.

The ATIP is comprised of a set of three TIP machines. Other than the power probe detector itself, each machine has a drive mechanism, a position indexing mechanism, and associated guide tubes for detector traveling. Within each ATIP machine, the ATIP detector is traversed via guide tubes and through desired index positions to the designated LPRM assembly calibration tubes. Flux readings along the axial length of the core are obtained while the detector is traversed along the fuel region, with the signal data sent to an ATIP control unit for data processing and storage. The data are then sent to the process computer for calibration and performance calculations. The whole ATIP operation can be fully automated, with manual control capability.

The MRBM utilizes a selected number of LPRM signals around each designated control rod to detect local power change during the rod withdrawal. If the averaged LPRM signal exceeds a preset rod block setpoint, a control rod block demand is issued. The setpoint is determined based on analysis which assures that the fuel thermal limits do not violate the safety limits. Since it monitors more than one region, it is called the multi-channel rod block monitor. The MRBM is a dual channel, highly reliable system.

The NMS provides trip signals to the RPS as part of the RPS safety protection function inputs. All trip setpoints are adjustable. The SRNM trip and the APRM trip are separate logics to the RPS, each interfacing with the RPS independently. Fail-safe logic is used for both subsystems. The NMS bypass function is performed within the NMS. The bypass functions of the SRNM and the APRM are separate and independent from each other. Both the SRNM and the APRM are designed to permit functional testing during normal plant operation. Provisions exist to limit access to trip setpoints and calibration controls.

All the SRNM, LPRM and APRM instruments are powered by four 120 VAC uninterruptible power supply (UPS) buses A, B, C, and D that correspond to the four safety divisions. Each bus supplies power to approximately one fourth of the total number of detectors. Loss of a power supply bus will cause the loss of the divisional instruments, including the SRNM and the APRM. The power for the ATIP is supplied from the instrument AC power source. The power supply for the MRBM is from the non-divisional 120 VAC UPS bus.

The SRNM and LPRM detectors and detector assemblies are designed to operate under normal and design basis abnormal conditions. The SRNM pre-amplifiers which are located in the reactor building, and the NMS instruments which are located in the control room, are designed to operate under all expected environmental conditions in those areas. The wiring, cables, and connectors in the drywell are designed for continuous duty under normal and design basis abnormal conditions.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.2.5 provides a definition of the inspections, tests, and/or analyses with associated acceptance criteria for the NMS.

Table 2.2.5: Neutron Monitoring System

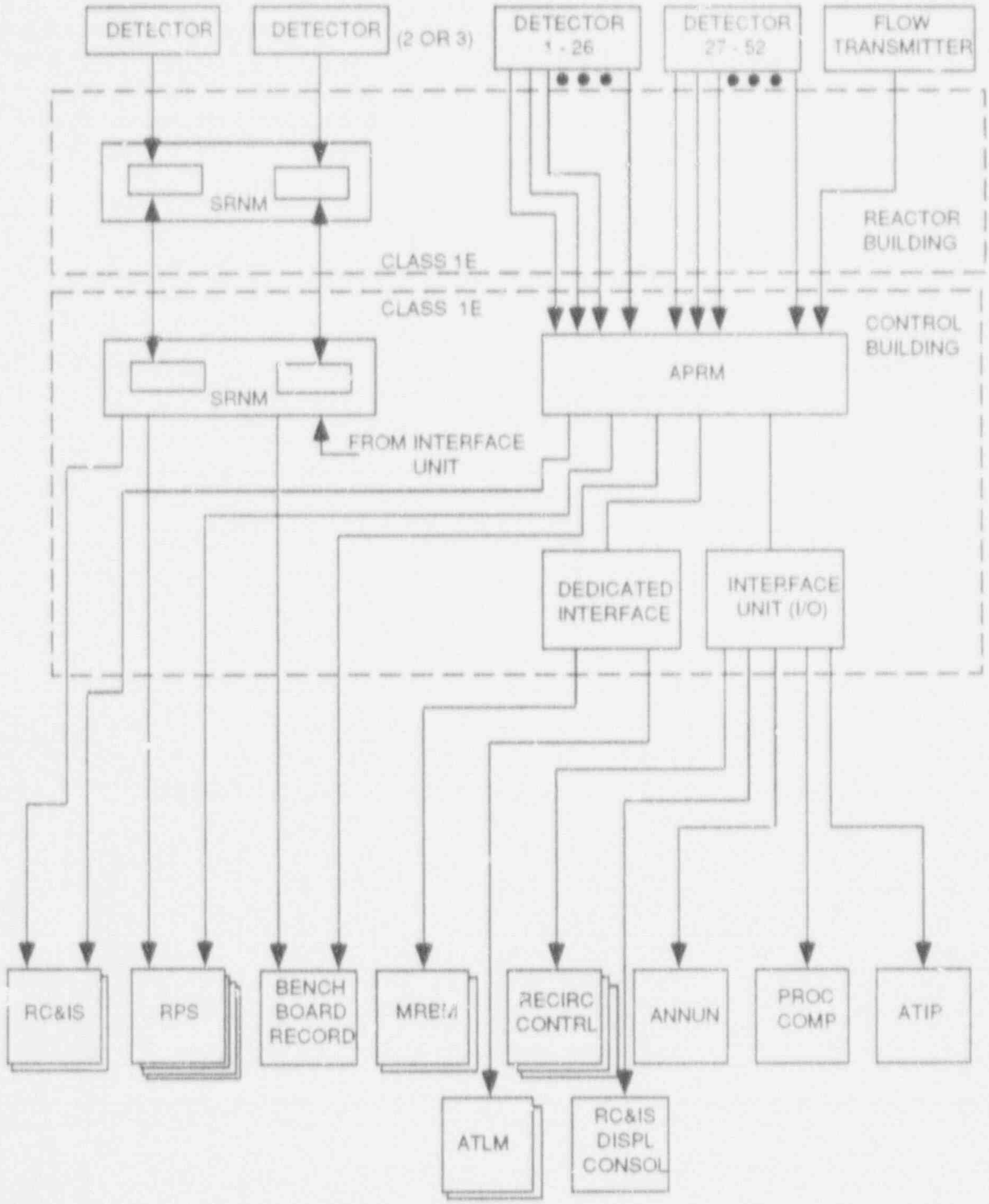
Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The power monitoring range for the SRNM shall be from shutdown to at least 15% rated power. The power monitoring range for the LPRM shall cover an equivalent core average power range from 1% to 125% of rated power.	1. Inspection of certification documents from the detector manufacturers will be conducted to confirm the specified power monitoring range.	1. The inspection must confirm the following detector performance range: a) SRNM: shutdown level to at least 15% of rated power; b) LPRM: individual detector overall range equivalent to a core average power of 1% to 125% of rated power.
2. A simplified system configuration is shown in Figure 2.2.5.	2. Inspections of installation records and plant walkdowns will be conducted to confirm that the installed equipment is in compliance with the design configuration defined in Figure 2.2.5.	2. The system configuration is in accordance with Figure 2.2.5.
3. The divisional assignment and separation of the four redundant SRNM and the PRNM subsystems shall be properly implemented.	3. Inspections and plant walkdowns will be conducted to confirm the four division redundancy and the electrical and physical separation of the four division SRNM and PRNM equipments.	3. The SRNM and the PRNM equipments must be arranged so that the basic requirements of equipment physical and electrical separation are met.
4. The trip functions of the SRNM and APRM are properly implemented as described in Section 2.2.5. The system is designed to permit functional testing of the NMS during normal plant operation.	4. SRNM and APRM trip functions will be tested through the testing of the electrical components. Other field tests will be also conducted after system installation to confirm system functional testing can be performed.	4. On the installed equipment, the system must be able to issue trip signals during functional test for the following trip functions: a) SRNM period trip; b) APRM upscale trip; c) APRM thermal power upscale trip; d) APRM rapid flow decrease trip; e) SRNM and APRM inoperative trip
5. The divisi[illegible]gnments of the SRNM and [illegible] supply is provided by the four 120 VAC [illegible]S buses.	5. [illegible]stem tests will be conducted after installation to confirm that the electrical power supply configuration is in complianc[illegible] with design commitments.	5. The installed equipment is powered from the four divisional Class 1E UPS power sources.

Table 2.2.5: Neutron Monitoring System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. The SRNM and APRM trip setpoints of trip signals to the RPS shall be adjustable and properly implemented, using applicable setpoint methodology.	6. Inspections and tests will be conducted to confirm that the setpoints are adjustable and are properly implemented.	6. The electric equipment must be tested to show that the setpoints are adjustable and the setpoint values are properly implemented according to plant technical specification.
7. Provisions exist to limit access to trip setpoints and calibration controls.	7. Inspections and tests will be conducted to confirm the existence of appropriate security controls.	7. Appropriate method of security controls must exist to change trip setpoints or to calibrate the instruments.



RC&IS: ROD CONTROL & INFORMATION SYSTEM
ATLM: AUTOMATED THERMAL LIMIT MONITOR, PART OF RC&IS
RECIR CONTRL: RECIRCULATION FLOW & CONTROL SYSTEM CONTROL

Figure 2.2.5 Neutron Monitoring System

2.2.6 Remote Shutdown System

Design Description

The Remote Shutdown System (RSS) for the Advanced Boiling Water Reactor (ABWR) provides remote manual control of normal and nuclear safety related systems necessary to bring the reactor to cold shutdown conditions in an orderly fashion from outside the main control room.

No Loss of Coolant Accident (LOCA), seismic event, or other abnormal plant condition, except loss of off-site power, is assumed to occur coincident with the event requiring the main control room evacuation. The RSS has two divisional panels and associated controls and indicators for monitoring the following interfacing systems:

(1) Residual Heat Removal System (RHR) (Pool cooling and shutdown cooling modes).

(2) High Pressure Core Flooder System (HPCF)

(3) Nuclear Boiler System (NBS) Safety Relief Valves

(4) Reactor Service Water System (RSW)

(5) Reactor Building Cooling Water System (RCW)

(6) Electrical Power Distribution System (EPDS)

(7) Atmospheric Control System (AC)

(8) Emergency Diesel Generator (D/G)

(9) Make-up Water Condensate System (MUWC)

(10) Flammability Gas Control System (FCS)

The RSS is classified as a safety-related system because it interfaces with nuclear safety-related equipment from other systems. The two remote shutdown control panels are Seismic Category I and are located in a single remote shutdown station in the Reactor Building. A physical barrier provides separation between the two panels. The RSS provides remote control capability through control and transfer switches in the RSS panels which override the controls from main control room and tansfer control to the RSS panels.

Indication for plant parameters is also provided on the remote shutdown panels to assure a safe and controlled shutdown of the plant. Figure 2.2.6 shows the RSS with the interfacing systems and control and indication functions provided.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.2.6 provides a definition of the visual inspections, tests and/or analyses, together with associated acceptance criteria, which will be performed for the RSS.

Table 2.2.6: Remote Shutdown System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. RSS provides a remote manual control of the following interfacing systems to bring the reactor to cold shutdown conditions: a. RHR (pool cooling and shutdown cooling modes) b. HPCF c. NBS Safety Relief Valves d. RSW e. RCW f. EPDS g. AC h. D/G i. MUWC j. FCS	1. Review of as-built documentation and visual inspections of the RSS will be performed. Testing of the RSS control functions will be performed.	1. RSS has the required plant system control capablity.
2. The RSS has two divisional panels for monitoring and controlling of the interfacing systems. The panels are physically separated and are located in a remote shutdown station.	2. Visual inspections and documentation review to confirm the appropriate location, isolation, and seismic capabilities of the panels.	2. The panels conform to their requirements for divisional separation and seismic criteria. They are located in a separate RSS station.
3. RSS provides indication of plant parameters in RSS panels to monitor a controlled shutdown of the plant.	3. Visual inspections and review of as-built documentation relating to RSS monitoring function.	3. The RSS has the required plant monitoring capability.

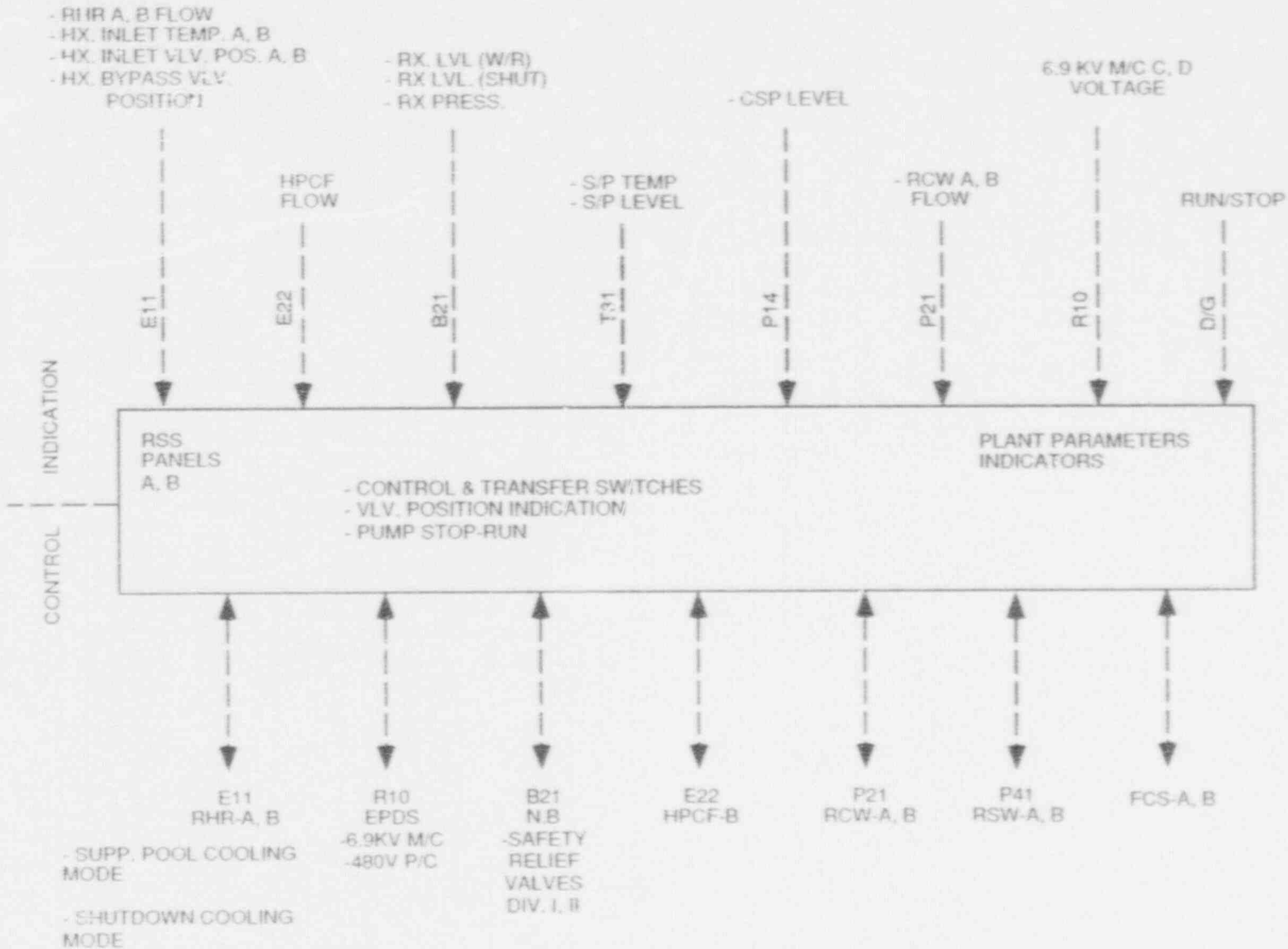


Figure 2.2.6 Remote Shutdown System

2.2.7 Reactor Protection System

Design Description

The Reactor Protection System (RPS) for the Advanced Boiling Water Reactor (ABWR) is a warning and trip system where initial warning and trip decisions are implemented with software logic installed in microprocessors. The primary functions of this system is to provide prompt protection against the onset and consequences of events or conditions that threaten the integrity of the fuel barrier. To accomplish this, the system is designed to: (1) make the logic decisions related to warning and trip conditions of the individual instrument channels, and (2) make the decision for system trip (emergency reactor shutdown) based on coincidence of instrument channel trip conditions.

The RPS is classified as a safety protection system (i.e., as differing from a reactor control system or a power generation system). The functions of the RPS and its components are safety-related. The RPS and the electrical equipment of the system are also classified as Safety Class 3, Seismic Category I and as IEEE electrical category Class 1E.

Basic system parameters are:

(1)	Number of independent divisions of equipment	4
(2)	Minimum number of sensors per trip variable (at least one per division)	4
(3)	Number of automatic trip systems (one per division)	4
(4)	Automatic trip logic used for plant sensor inputs (per division)	2-out-of-4
(5)	Separate automatic trip logic used for division trip outputs	2-out-of-4
(6)	Number of separate manual trip systems	2
(7)	Manual trip logic	2-out-of-2

The RPS consists of instrument channels, trip logics, trip actuators, manual controls, and scram logic circuitry that initiates rapid insertion of control rods (scram) to shut down the reactor for situations that could result in unsafe reactor operating conditions. The RPS also establishes the required trip conditions that are appropriate for the different reactor operating modes and provides status and control signals to other systems and annunciators. The RPS related equipment includes detectors, switches, microprocessors, solid-state logic circuits, relay type contactors, relays, solid-state load drivers, lamps, displays, signal transmission routes, circuits, and other equipment which are required to execute the functions of the system. To accomplish its overall function, the RPS utilizes the functions of the essential multiplexing system (EMS) and of portions of the Safety System Logic and Control (SSLC) System.

As shown in Figure 2.2.7a, the RPS interfaces with the Neutron Monitoring System (NMS), the Process Radiation Monitoring (PRRM) System, the Nuclear Boiler System (NBS), the Control Rod Drive (CRD) System, the Rod Control and Information System (RC&IS), the Recirculation Flow Control (RFC) System, the Process Computer System, and with other plant systems and equipment. RPS components and equipment are separated or segregated from process control system sensors, circuits and functions such as to minimize control and protection system interactions. Any necessary interlocks from the RPS to control systems are through isolation devices.

The RPS is a four-division system which is designed to provide reliable single-failure-proof capability to automatically or manually initiate a reactor scram while maintaining protection against unnecessary scrams resulting from single failures in the RPS. The RPS remains single-failure proof even when one entire division of channel sensors is bypassed and/or when one of the four automatic RPS trip logic systems is out-of-service. Equipment within the RPS is designed to fail into a trip initiating state or other safe state on loss of power or input signals or disconnection of portions of the system. The system also includes trip bypasses and isolated outputs for display, annunciation or performance monitoring. RPS inputs to annunciators, recorders and the computer are electrically isolated so that no malfunction of the annunciating, recording, or computing equipment can functionally disable any portion of the RPS. The RPS related equipment is divided into four redundant divisions of sensor (instrument) channels, trip logics and trip actuators, and two divisions of manual scram controls and scram logic circuitry. The automatic and manual scram initiation logic systems are independent of each other and use diverse methods and equipment to initiate a reactor scram. The RPS design is such that, once a full reactor scram has been initiated automatically or manually, this scram condition seals-in such that the intended fast insertion of control rods into the reactor core can continue to completion. After a time delay, the design allows operator action to return the RPS to normal.

Figure 2.2.7b shows the RPS divisional separation aspects and the signal flow paths from sensors to scram pilot valve solenoids. Equipment within a RPS related sensor channel consists of sensors (transducers or switches), multiplexers, and digital trip modules (DTMs). The sensors within each channel monitor for abnormal operating conditions and send either discrete bistable (trip/no trip) or analog signals directly to the RPS related DTM, or else send analog output signals to the RPS related DTM by means of the remote multiplexer unit (RMU) within the associated division of essential multiplexing system (EMS). The RPS related bistable switch type sensors or, in the case of analog channels, the RPS software logic will initiate reactor trip signals within the individual sensor channels, when any one or more of the conditions listed below exist within the plant during different conditions of reactor operation, and will initiate reactor scram if coincidence logic is satisfied (the system monitoring the process condition is indicated in brackets).

(1) Turbine Stop Valves Closure (above 40% power levels) [RPS]

(2) Turbine Control Valves Fast Closure (above 40% power levels) [RPS]

(3) NMS monitored SRNM and APRM conditions exceed acceptable limits [NMS]

(4) High Main Steam Line Radiation [PRRM System]

(5) High Reactor Pressure [NBS]

(6) Low Reactor Water Level (Level 3) [NBS]

(7) High Drywell Pressure [NBS]

(8) Main Steam Line Isolation (MSLI) (Run mode only) [NBS]

(9) Low Control Rod Drive Accumulator Charging Header Pressure [CRD]

(10) Operator-initiated Manual Scram [RPS]

The RPS outputs, NMS outputs, PRRM System outputs, and the MSLI and manual scram outputs are provided directly to the RPS by hard-wired or fiber-optic signals. The NBS and the CRD System provide other sensor outputs through the EMS. Analog-to-digital conversion of these latter sensor output values is done by EMS equipment. The DTM in each division uses either the discrete bistable input signals, or compares the current values of the individual monitored analog variables with their trip setpoint values, and for each variable sends a separate, discrete bistable (trip/no trip) output signal to the trip logic units (TLUs) in all four divisions of trip logics. The DTMs and TLUs utilized by the RPS are microprocessor components within the SSLC System.

RPS related equipment within a RPS division of trip logic consists of manual control switches, bypass units (BPUs), trip logic units (TLUs), and output logic units (OLUs). The manual control switches and the BPUs, TLUs and OLUs are components of the RPS portions of the SSLC System. The various manual switches provide the operator a means to modify the RPS trip logic for special operation, maintenance, testing, and system reset. The bypass units perform bypass and interlock logic for the single division of channel sensors bypass function and for the single division TLU bypass function. The TLUs perform the automatic scram initiation logic, normally checking for two-out-of-four coincidence of trip conditions in any set of instrument channel signals coming from the four-division DTMs or from isolated bistable inputs from all four divisions of NMS equipment, and outputting a trip signal if any one of the two-out-of-four coincidence checks is satisfied. TLU trip decision logic in all four RPS TLUs becomes a check for two-out-of-three coincidence of trip conditions if any one division of channel sensors has been bypassed. The OLUs perform the division trip, seal-in, reset and trip test functions. Trip signals from the OLUs within a single division are used to trip the trip actuators, which are fast response, bistable, solid-state load drivers for automatic scram initiation, and are trip relays for air header dump (backup scram) initiation. Load driver outputs toggled by a division OLU interconnect with load driver outputs toggled by other division OLUs into two separate arrangements, which results in two-out-of-four scram logic (i.e., reactor scram will occur if load drivers associated with any two or more divisions receive trip signals).

The isolated AC load drivers are fast response time, bistable, solid-state, high current interrupting devices. The operation of the load drivers is such that a trip signal on the input side will create a high impedance, current interrupting condition on the output side. The output side of each load driver is electrically isolated from its input signal. The load driver outputs are arranged in the scram logic circuitry, between the scram pilot valves' solenoids and the solenoids' AC power source, such that, when in a tripped state, the load drivers will cause deenergization of the scram pilot valve solenoids (scram initiation). Normally closed relay contacts are arranged in the two backup scram logic circuits, between the air header dump valve solenoid and air header dump valve DC solenoid power source, such that, when in a tripped state (coil deenergized), the relays will cause energization of the air header dump valve solenoids (air header dump initiation). Associated DC voltage relay logic is also utilized to effect scram reset permissives and scram-follow (control rod run-in) initiation.

The RPS design for the ABWR is testable for correct response and performance, in overlapping stages, either on-line or off-line (to minimize potential of unwanted trips). Access to bypass capabilities of trip functions, instrument channels or a trip system and access to setpoints, calibration controls and test points are under administrative control.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.2.7 provides a definition of the visual inspections, tests and/or analyses, together with associated acceptance criteria, which will be used by the RPS.

Table 2.2.7: REACTOR PROTECTION SYSTEM

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. RPS components and equipment are kept separate from equipment associated with process control systems.	1. Visual field inspections and analyses of relationship of installed RPS equipment and of installed equipment of interfacing process control systems (and/or tests of interfaces) to confirm that appropriate isolation methods have been used to satisfy separation and segregation requirements.	1. RPS equipment installation acceptable if inspections, analyses and/or tests confirm that any failure in process control systems can not prevent RPS safety functions.
2. Fail-safe failure modes result upon loss of power or disconnection of components.	2. Field tests to confirm that trip conditions and/or bypass inhibits result upon loss of power or disconnection of components.	2. Acceptable if safe state conditions result upon loss of power or disconnection of portions of the RPS.
3. Provisions exist to limit access to trip setpoints, calibration controls and test points.	3. Visual field inspections of the installed RPS equipment will be used to confirm the existence of appropriate administrative controls.	3. The RPS hardware/firmware will be considered acceptable if appropriate methods exist to enforce administrative control for access to sensitive areas.
4. The four redundant divisions of RPS equipment and the four automatic trip systems are independent from each other except in the area of the required coincidence of trip logic decisions and are both electrically and physically separated from each other. Similarly, the two manual trip systems are separate and independent of each other and of the four automatic trip systems.	4. Inspections of fabrication and installation records and construction drawings or visual field inspections of the installed RPS equipment will be used to confirm the quadruple redundancy of the RPS and the electrical and physical separation aspects of the RPS instrument channels and the four automatic trip systems, as well as their diversity and independence from the two manual trip systems.	4. Installed RPS equipment will be determined to conform to the documented description of the design as depicted in Figure 2.2.7b.

Table 2.2.7: REACTOR PROTECTION SYSTEM (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. It is possible to conduct verifications of RPS operations, both on-line and off-line, by means of (a) individual instrument channel functional tests, (b) trip system functional tests and (c) total system functional tests.	5. Preoperational tests will be conducted to confirm that system testing such as channel checks, channel functional tests, channel calibrations, coincident logic tests and paired control rods scram tests can be performed. These tests will involve simulation of RPS testing modes of operation. Interlocks associated with the reactor mode switch positions, and with other operational and maintenance bypasses or test switches, will be tested and annunciation, display and logging functions will be confirmed.	5. The installed RPS configuration, controls power sources and installations of interfacing systems supports the RPS logic system functional testing and the operability verification of design as follows: a. Installed RPS hardware/firmware initiates trip conditions in all four RPS automatic trip systems upon coincidence of trip conditions in two or more instrument channels associated with the same trip variable(s). b. Installed system initiates full reactor trip and emergency shutdown (i.e., deenergization of both solenoids associated with all scram pilot valves) upon coincidence of trip conditions in two or more of the four RPS automatic trip systems. c. Installed system initiates trip conditions in both RPS manual trip systems if both manual trip switches are operated or if the reactor mode switch is placed in the "shutdown" position. d. Trip system (automatic and manual) trip conditions seal-in and protective actions go to completion. Trip reset (after appropriate delay for trip completion) requires deliberate operator action.

Table 2.2.7: REACTOR PROTECTION SYSTEM (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
		5. (Continued) e. Installed system energizes both air header dump (backup scram) valves of the CRD hydraulic system, and initiates CRD motor run-in, concurrent only with a full scram condition. f. When not bypassed, trips result upon loss or disconnection of portions of the system. When bypassed, inappropriate trips do not result. g. Installed system provides isolated status and control signals to data logging, display and annunciator systems. h. Installed system demonstrates operational interlocks (i.e., trip inhibits or permissives) required for different conditions of reactor operation.
6. The RPS design provides prompt protection against the onset and consequences of events or conditions that threaten the integrity of the fuel barrier.	6. Preoperational tests will be conducted to measure the RPS and supporting systems response times to: (a) monitor the variation of the selected processes; (b) detect when trip setpoints have been exceeded; and, (c) execute the subsequent protection actions when coincidence of trip conditions exist.	6. The RPS hardware/firmware response to initiate reactor scram will be considered acceptable if such response is demonstrated to be sufficient to assure that the specified acceptable fuel design limits are not exceeded.

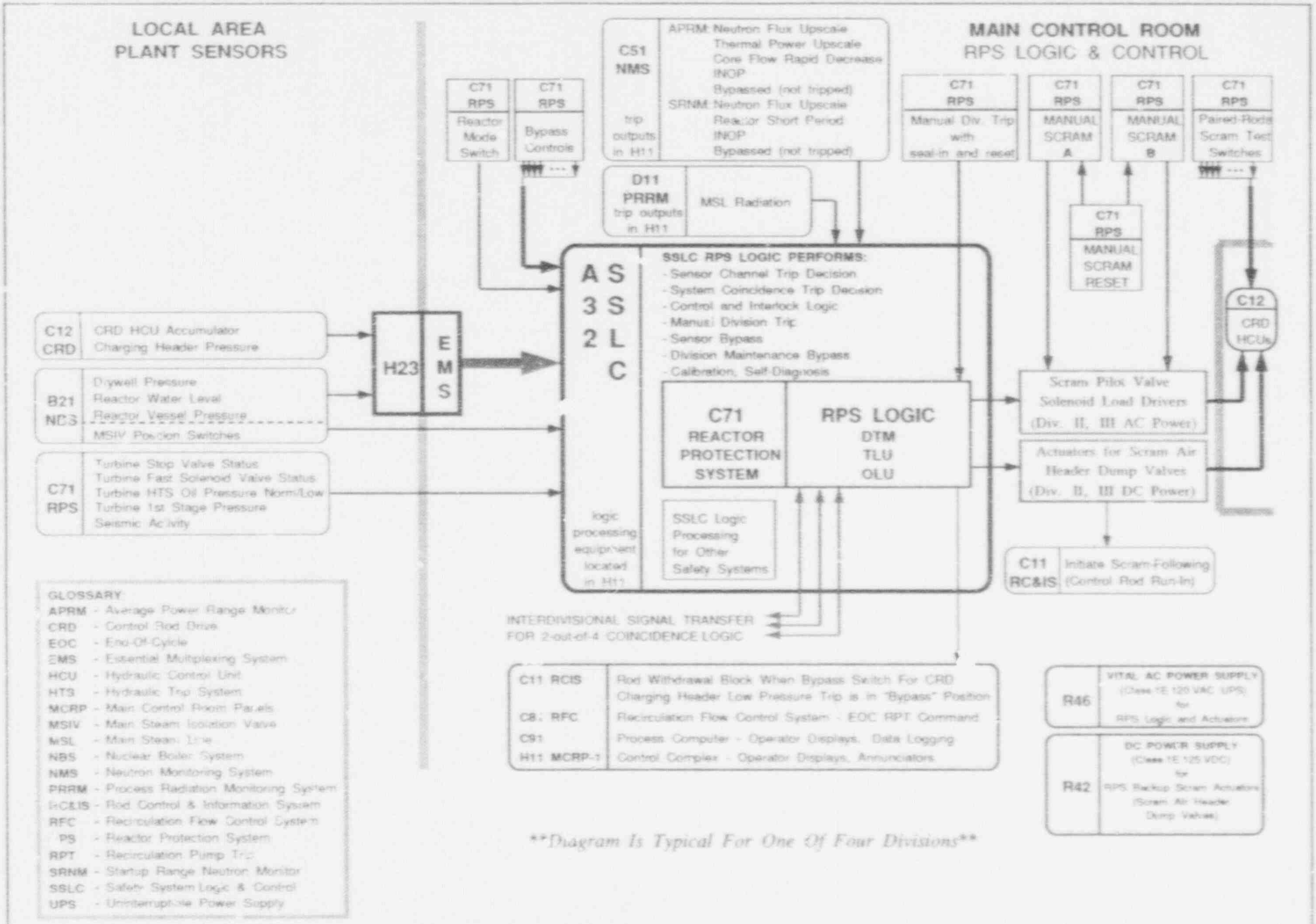


Figure 2.2.7a Reactor Protection System

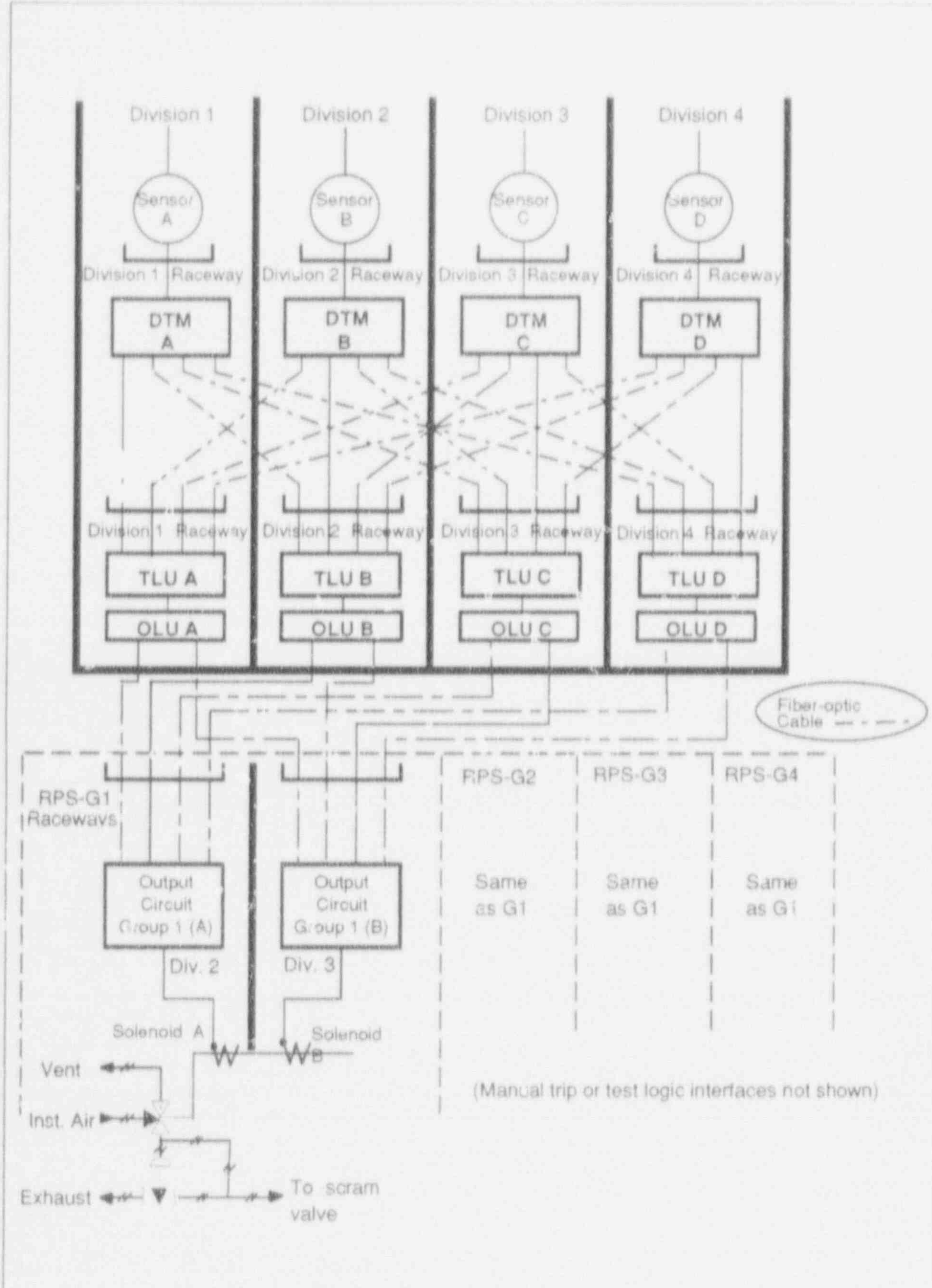


Figure 2.2.7b Reactor Protection System

2.2.8 Recirculation Flow Control System

Design Description

The Recirculation Flow Control (RFC) System controls reactor power by controlling the recirculation flow rate of the reactor core water. Reactor recirculation flow and core flow is varied by modulating the Recirculation Internal Pump (RIP) speeds/flows through the voltage and frequency modulation of adjustable speed drive outputs. Refer to Figure 2.2.8.

The RFC System consists of the triplicated process controller, solid state Adjustable Speed Drives (ASDs), switches, sensors, and alarm devices provided for operational manipulation of the ten RIPs and the surveillance of associated equipment. Recirculation flow control is achieved either by manual operation, or by automatic operation if the power level is above approximately 70% of rated. The reactor internal pumps can be driven to operate anywhere between minimum speed and 100% of rated speed with the variable voltage, variable frequency power source supplied by the ASDs.

This system is a power generation system and is classified as non-safety-related.

The RFC System is designed to allow both automatic and manual operation. In the automatic mode called "Master Auto" mode *Automatic Load Following (ALF) operation) the master controller generates a demand signal for balancing out the load demand error to zero. This demand signal is forwarded to the flow controller which generates a flow demand signal. The flow demand signal is adjusted by a flow demand set down function to lower the recirculation flow when the sensed reactor flux is above 105%. The speed controllers in the ASDs generate speed demand based on the flow demand from the flow controller. The speed demand causes adjustment of RIP motor power input which changes the operating speed of the RIP and hence core flow and core power. This process continues until both the errors existing at the input of the flow controller and master controller are driven to zero. The flow controller can remain in automatic even though the master controller is in manual.

The reactor power change resulting from the change in recirculation flow causes the pressure regulator to reposition the turbine control valves. If the original demand signal was a load/speed error signal, the turbine responds to the change in reactor power level by adjusting the control valves, and hence its power output, until the load/speed error signal is reduced to zero.

In the semi-automatic mode, the operator sets the total core flow demand and the RFC System responds to maintain constant core flow. Core flow control is achieved by comparing the core flow feedback, which is calculated from the core plate differential pressure signals, with the operator supplied core flow set point.

In total manual control, the operator can directly manipulate the RIP speeds. Pump speeds can be controlled individually or collectively. When individually controlled, pump speed demand is obtained through the operator console and transmitted directly to the individual ASD for pump frequency control. In collective manual operation, a common speed set point is used for controlling each RIP which has been placed in the GANG speed control mode.

The recirculation flow control system is also used to control the start up of the reactor internal pumps. To minimize thermal shock to the reactor vessel, the RFC System will prevent start up of an idle RIP if the temperature difference of the vessel bottom coolant to the saturated water temperature corresponding to the steam dome pressure is above a predetermined value. In the even of either (a) turbine trip or generator load rejection above a predetermined reactor power level, (b) reactor pressure exceeds the high dome pressure trip set point, or (c) reactor water level drops below the Level 3 set point, logic will automatically be initiated to trip off a group of four RIPs.

ASDs are used to provide electrical power and speed control to the pump motors in the RIPs. The ASD receives electrical power from a power plant bus at a constant AC voltage and frequency. The ASD converts this to a variable frequency and voltage in accordance with the speed demand requested by the RFC System controller.

The ASD is capable of supporting three modes of operation: start up, normal, and shutdown. When the start up mode is selected, the inverter output quickly steps up from zero to the required motor power corresponding to the minimum pump speed and holds at that output frequency. When the normal operation mode is selected, continuous output power frequency between minimum speed and 100% is allowed. The operation of the shutdown mode is exactly reverse that of the normal and start up mode; ASD output is automatically ramped to minimum speed frequency, then stepped down to zero.

The RFC System control functional logic is performed by a triply redundant, microprocessor based fault tolerant digital controller (FTDC). The FTDC consists of three identical processing channels working in parallel to provide fault tolerant operation.

The RFC System design consists of two main control loops, (1) the core flow loop, which modulates pump speed demand to provide the desired core flow rate, and (2) the automatic load following (ALF) which modulates the core flow demand in response to the load demand error. In addition, pump speed in each RIP can be manually controlled individually or collectively.

In the core flow control mode, sensed core flow calculated by the core plate differential pressure method is compared with the core flow demand supplied by the operator or obtained from the master controller, depending on the RFC system operating mode. This flow error is input to the core flow controller to drive pump speed demand.

In ALD mode, the master controller receives a load demand signal from the steam bypass and pressure control (SP&PC) system in response to any combination of local operator load set point inputs, automatic generation control inputs, or grid load changes indicated by grid frequency variation.

When in local control, the operator's control panel provides the operator the capability to select the operating mode of the system and to initiate certain manual actions. Indications and alarms are provided to keep the operator informed of the system operational modes and equipment status, thereby allowing him to quickly determine the origin of any abnormal conditions.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.2.8 provides a definition of the inspections, tests, and/or analyses, together with the associated acceptance criteria, which will be undertaken for the RFC.

Table 2.2.8a: Recirculation Flow Control System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Test, Analyses	Acceptance Criteria
1. The configuration of the RFC system is shown in Figure 2.2.8-1.	1. Inspections of the as-built RFC system shall be performed	1. Actual RFC system configuration, for those components shown, conforms with Figure 2.2.8-1.
2. Reactor internal pumps (RIPs) will operate at any speed between minimum speed and 100% of rated speed.	2. Operation of the pumps at any speed between minimum speed and 100% of rated shall be performed.	2. Pumps shall operator within design specification limits at any speed between 10% and 100% of rated.
3. The RFC System may be operated in automatic mode above approximately 70% of rated power.	3. The RFC System shall be operated at power levels greater than approximately 70% rated.	3. The RFC System shall operate in automatic mode within design specification limits at any power level above approximately 70% rated.
4. The RFC System shall be used to control the start up or shut down of the RIPs.	4. The RFC System shall be operated in the start up and shutdown modes.	4. The RFC System shall operate within the design specification limits in the start up and shutdown modes. The pump shall be ramped from 0% to 30% and held and then shall be stepped down to 0%.
5. The RFC System shall be interlocked so as to prevent start up of a idle RIP if the vessel bottom temperature is not within 144°F of the saturated dome pressure equivalent temperature.	5. The RFC System shall be operated so as to start up an idle RIP when the vessel bottom temperature is not within 144°F of the saturated dome pressure temperature equivalent.	5. The RFC System shall prevent start up of an idle RIP under conditions specified in the design specification.
6. A select group of RIPs shall trip off in the event of either (a) turbine trip or generator load rejection, (b reactor pressure exceeds high dome pressure trip set point, or (c) reactor level drops below Level 3.	6. The RFC System shall be operated and the following events shall be simulated: (a) turbine trip (b) generator load rejection (c) low reactor dome pressure (d) low vessel level	6. The RFC System shall operate within design specification limits under all simulated fault conditions.

2.2.9 Automatic Power Regulator System

Design Description

The Automatic Power Regulator (APR) system is classified as a power generation system and is not required for safety. Safety events requiring control rod scram are sensed and controlled by the safety-related reactor protection system (RPS), which is completely independent of the APR.

The APR system controls reactor power during reactor startup, power generation, and reactor shutdown by appropriate commands to change rod positions, or to change reactor recirculation flow. The APR system also controls the pressure setpoint or turbine bypass valve position during reactor heatup and de-pressurization (e.g. to control the reactor cool down rate). The automatic power regulator system consists of redundant process controllers. Automatic power regulation is achieved by appropriate control algorithms for different phases of the reactor operation which include approach to criticality, heatup, reactor power increase, automatic load following, reactor power decrease, and reactor de-pressurization and cool down. The automatic power regulator system receives input from the plant process computer, power generation control system, the steam bypass and pressure control system, and the operator's control console. The output demand signals from automatic power regulator system are sent to rod control and information system to position the control rods, to the recirculation flow control system to change reactor coolant recirculation flow, and to the steam bypass and pressure control system for automatic load following operations. The power generation system performs the overall plant startup, power operation, and shutdown functions. The automatic power regulation system performs only those functions associated with reactor power changes and with reactor pressure controller setpoint (or turbine bypass valve position) changes during reactor heatup or de-pressurization. A simplified functional block diagram of the automatic power regulation system is provided in Figure 2.2.9.

The automatic power regulation system control functional logic is performed by redundant, microprocessor-based fault-tolerant digital controllers (FTDC). The FTDC performs many functions. It reads and validates inputs from the non-essential multiplexing system (NEMS). It performs the specific power control calculations and processes the pertinent alarm and interlock functions, then updates all system outputs to the NEMS. To prevent computational divergence among the redundant processing channels, each channel performs a comparison check of its calculated results with the other redundant channels. The internal FTDC architecture features redundant multiplexing interfacing units for communications between the NEMS and the FTDC processing channels.

During normal operation, the automatic power regulation system interfaces with the operator's console to perform its desired functions. The operator's control panel for automatic plant startup, power operation, and shutdown functions is part of the power generation control system. The power generation control system initiates demand signals to various controllers to carry out the pre-defined control functions. The functions associated with reactor power control are performed by the automatic power regulation system. For reactor power control, the automatic power regulation system contains algorithms that can change reactor power by control rod motions, or by reactor coolant recirculation flow changes, but not both at the same time. During automatic load following operation, the automatic power regulation system interfaces with the steam bypass and pressure control system to coordinate main turbine and reactor power changes to accomplish load following.

The normal mode of operation for the automatic power regulator system is automatic. If any system or component conditions are abnormal during execution of the prescribed sequences of operation, the power generation control system will be automatically switched into the manual mode and the operator can manipulate control rods and recirculation flow through the normal controls. A failure of the automatic power regulation system will not prevent manual controls of the reactor, nor will it prevent safe shutdown of the reactor.

The automatic power regulation system digital controllers are powered by redundant uninterruptible non-class 1E power supplies and sources. No single power failure will result in the loss of any automatic power regulation system function.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.2.9 provides a definition of the inspections, tests and/or analyses, together with associated acceptance criteria, which will be used by APR.

Table 2.2.9: Automatic Power Regulator System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. This system is powered by redundant uninterruptible power supplies.	1. Test of loss of power due to single channel power supply failure shall demonstrate no loss of APR function.	1. There is no loss of APR function by loss of one channel power supply.
2. Triplicated, fault tolerant digital controllers with self test and diagnostic capabilities shall be used.	2. Inspect FTDCs and perform validation testing.	2. The fault tolerant digital controllers' self test and on-line diagnostic test features are capable of identifying and isolating failures of input signals, I/O cards, buses, power supplies, processors and inter-processors communication.
3. The APR design provides automatic power control in different modes of operation	3. Preoperational tests will be conducted to confirm the automatic power regulation capability in different modes of operation.	3. The APR controls power automatically during various modes of operation.

During normal operation, the automatic power regulation system interfaces with the operator's console to perform its desired functions. The operator's control panel for automatic plant startup, power operation, and shutdown functions is part of the power generation control system. The power generation control system initiates demand signals to various controllers to carry out the pre-defined control functions. The functions associated with reactor power control are performed by the automatic power regulation system. For reactor power control, the automatic power regulation system contains algorithms that can change reactor power by control rod motions, or by reactor coolant recirculation flow changes, but not both at the same time. During automatic load following operation, the automatic power regulation system interfaces with the steam bypass and pressure control system to coordinate main turbine and reactor power changes to accomplish load following.

The normal mode of operation for the automatic power regulator system is automatic. If any system or component conditions are abnormal during execution of the prescribed sequences of operation, the power generation control system will be automatically switched into the manual mode and the operator can manipulate control rods and recirculation flow through the normal controls. A failure of the automatic power regulation system will not prevent manual controls of the reactor, nor will it prevent safe shutdown of the reactor.

The automatic power regulation system digital controllers are powered by redundant uninterruptible non-class 1E power supplies and sources. No single power failure will result in the loss of any automatic power regulation system function.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.2.9 provides a definition of the inspections, tests and/or analyses, together with associated acceptance criteria, which will be used by APR.

2.2.10 Steam Bypass and Pressure Control System

Design Description

The Steam Bypass and Pressure Control (SB&PC) System is a non-safety-related system. It is a control system only, and consists of three redundant fault tolerant digital controllers (FTDCs) for control algorithms and logic along with indicators and alarms for operator information and the non-safety-related power supplies to power each FTDC. Because of the system's triple redundancy, it is possible to lose one logic channel without impacting the system functions. In addition, each FTDC is equipped with self-test and on-line diagnostic capabilities for identifying and isolating failure of input/output signals, buses, power supplies, processors and interprocessor communications. These on-line tests and diagnostics can be performed without interrupting the normal control operation of the SB&PC System. The SB&PC System receives input signals from other systems and sensors as shown in Figure 2.2.10 and as follows:

(1) Steam bypass valve position switches

(2) Steam bypass valve servo current sensors

(3) TCS turbine trip sensors

(4) TCS power/load unbalance relay operation

(5) Turbine Bypass System (TBS) hydraulic power supply trouble sensors

(6) Nuclear Boiler System (NBS) Main Steam Isolation Valve (MSIV) position switches

(7) NBS narrow and wide range dome pressure transmitters

(8) Steam Extraction System main condenser low vacuum sensors

(9) Operator manual commands and manual switch positions

The SB&PC system provides output signals to:

(1) Turbine Control System (TCS)

(2) Automatic Power Regulation (APR) System

(3) Recirculation Flow Control System

(4) Various related control room indicators and alarms

(5) Process computer

The primary function of the pressure control portion of the SB&PC System is to efficiently control the reactor system pressure during plant startup/shutdown, power generation, and load-following modes of plant operation, through control of turbine control and/or steam bypass valves. The system maintains plant stability during pressure setpoint changes.

The SB&PC System also has several secondary functions used during non-emergency situations and plant transients, none of which are safety related.

Additional reactor system pressure control functions are provided by other systems when the MSIVs are closed.

The function of the steam bypass portion of the SB&PC System is to control steam pressure by sending steam directly to the main condenser whenever reactor steam production exceeds main turbine steam flow demand. The system provides transfer capability between steam bypass valves and turbine control valves, and can accommodate load rejection.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.2.10 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the SB&PC System.

Table 2.2.10: Steam Bypass and Pressure Control System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Each FTDC is equipped with self-test and on-line diagnostic capabilities for identifying and isolating failure of input/output signals, buses, power supplies, processors and interprocessor communications. These on-line tests and diagnostics can be performed without interrupting the normal control operation of the SB&PC System.	1. Perform a on-line self-test with complete diagnostics based on the parameters shown in the design description (Section 2.2.10).	1. The results of the self-test confirms system operation.
2. The system incorporates redundant control channels.	2. The system shall be tested by simulating failure of one operating controller.	2. The system continues to function during loss of one operating controller.
3. The system is powered by redundant uninterruptable power supplies.	3. Loss of one power supply shall demonstrate no loss of functions of SB&PC system.	3. There is no loss of SB&PC functions by loss of any one power supply.

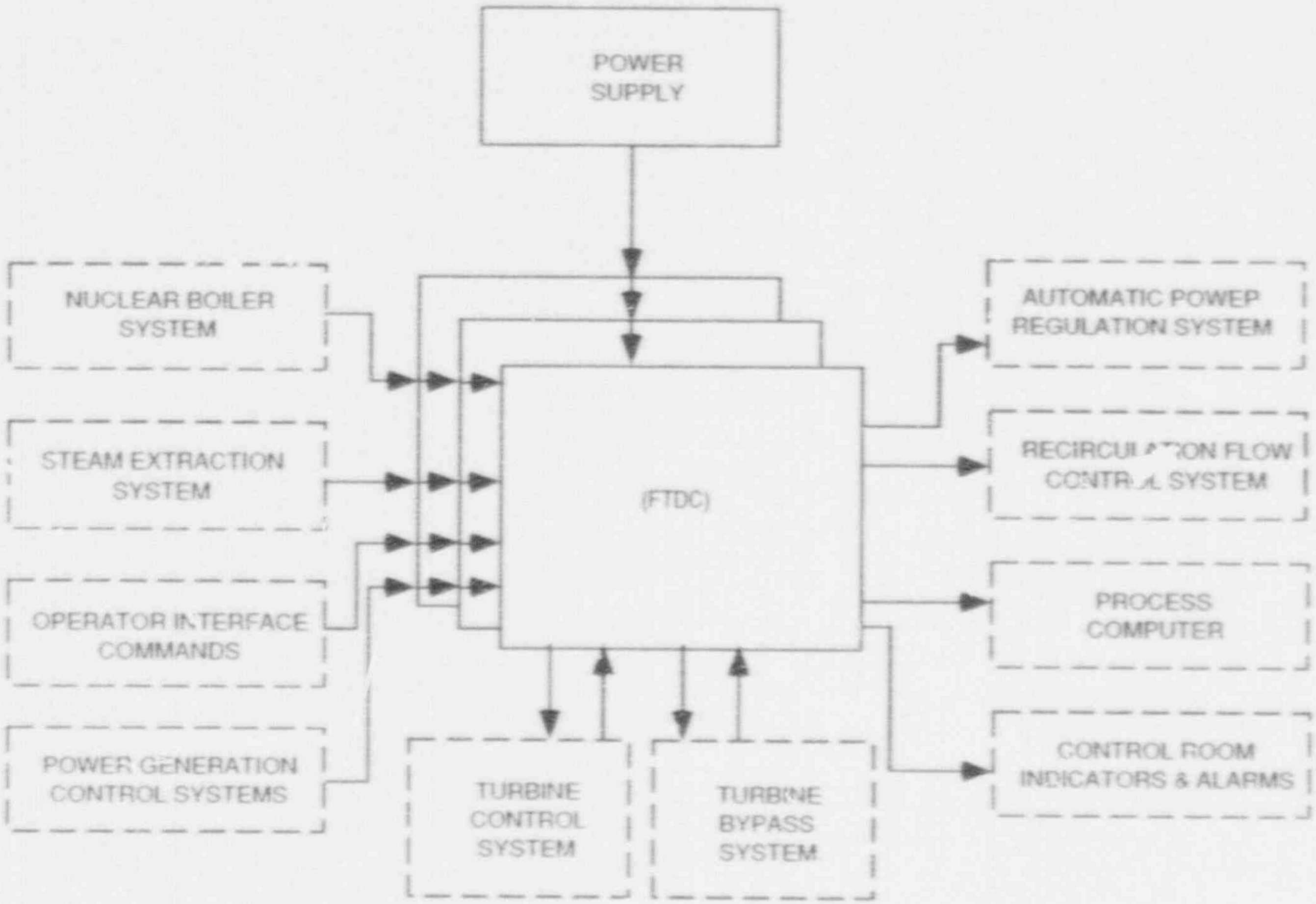


Figure 2.2.10 Steam Bypass and Pressure Control System

2.2.11 Process Computer System

Design Description

The Process Computer System (PCS) is a non-safety-related system. Its purpose is to promote efficient plant operation by:

(1) performing the functions and calculations necessary for the evaluation of plant operation;

(2) providing a permanent historical record for plant operating activities and abnormal events;

(3) providing analysis, evaluation and recommendation capabilities for start-up, normal operation, safe plant shutdown and abnormal operating and emergency conditions;

(4) providing the ability to directly control certain non-safety-related plant equipment through on-screen technology.

All division to division and safety to non-safety interfacing circuits are made up of fiber optic cables, which act as optical isolators for electrical separation. All power to the PCS is supplied by a non-safety related redundant, uninterruptible power supply. No single power failure will cause the loss of any PCS function.

The PCS has self-checking provisions. It performs diagnostic checks to determine the operability of certain portions of the system hardware and performs internal programming checks to verify that input signals and selected program computations are either within specific limits or within reasonable bounds.

The PCS is composed of two subsystems; the Performance Monitoring and Control System (PMCS) and the Power Generation Control System (PGCS). Neither of which serve a safety function. The PMCS and the PGCS are functions of the PCS, implemented by various programmed routines.

Performance Monitoring and Control System

The PMCS is a set of software routines for the PCS Input/Output Modules and various CPUs to supply various functions and calculations. The basic input types include but are not limited to the following:

(1) Various analog pressure signals from sensors on or in the Vessel, the drywell, individual equipment and the various plant buildings.

(2) Various analog temperature signals from sensors on or in the Vessel, the drywell, individual equipment and the various plant buildings.

(3) Various analog coolant and steam flow signals from sensors on or in the various pumps and pipes throughout the plant.

(4) Various digital "On/Off" and "Open/closed" signals from various switches and valve controllers throughout the plant.

(5) Various operator requests input through the various consoles.

The basic output types include but are not limited to the following:

(1) Plant Operating Conditions

(2) Process Trends

(3) Alarms

(4) Results of Performance Calculations

(5) Operator Requests

(6) Switchyard Operating Conditions

The types of calculations performed include but are not limited to the following:

(1) Reactor core performance calculation

(2) Plant performance calculation

The function types performed in addition to the calculations include but are not limited to the following:

(1) Data Accumulation

(2) Indication of Control Rod Position

(3) Surveillance test guide

Power Generation Control System

The PGCS is a function of the PCS. It is a software routine in which one or more CPUs act as a top level controller. It contains the algorithms for the automated control sequences associated with plant start-up, shutdown, and normal power generation. It receives the same type inputs as described in 2.2.11.1 and issues control commands and adjusts set-points of subloop controllers to support that automation. The automation process is divided into phases corresponding to plant start-up, shutdown, and normal power generation. Each phase is then divided into several break-points, or logical steps in plant operation. Automation proceeds under PCS control until the end of a break-point division is reached, at which time, the operator must actuate a break-point switch before automation can continue.

Inspections, Tests Analyses and Acceptance Criteria

Table 2.2.11 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the PCS.

Table 2.2.11: Process Computer System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Test, Analysis	Acceptance Criteria
1. The PCS has self - checking provisions. It performs diagnostic checks to determine the operability of certain portions of the system hardware and performs internal programming checks to verify that input signals and selected program computations are either within specific limits or within reasonable bounds.	1. Perform the self-checking test with complete diagnostics, of the functions listed in Subsection 2.2.11 using the manufacturer's operations and maintenance manual.	1. The results of the self-checking test confirms satisfactory system operation.
2. No single power failure will cause the loss of any PCS function.	2. The system shall be tested by simulating failure of one of the system power supplies.	2. The system continues to function during loss of one power supply.
3. In the event of the PCS going off-line or other trouble with the system, PGCS is easily separated from the control circuits and the plant will be safely controlled by the subloop controllers.	3. The system shall be tested by simulating loss of the PCS.	3. Testing results conform to plant response and stability requirements when the systems are manually controlled with the system subloop controller.

2.2.12 Refueling Platform Control Computer

The Refueling Platform will be computer controlled from the operator station on the refueling floor.

Design Description—Control Computer

The computer will provide X,Y and Z location of the refueling mast. Mast and platform will be controlled by various limits on their functions and movements.

Inspections, Tests, Analyses and Acceptance Criteria

No entries for this system.

2.2.13 CRD Removal Machine Control Computer

No Tier 1 entry for this system.

2.3 Radiation Monitoring

2.3.1 Process Radiation Monitoring (PRM) System

Design Description

The primary function of this system is to (a) monitor and record the various gaseous and liquid process streams and effluent releases, (b) initiate alarms in the MCR to warn operating personnel to the high radiation activity, and (c) initiate the appropriate safety actions and controls to prevent further radioactivity releases to the environment.

This system provides both safety and non-safety instrumentation for radiological monitoring, sampling and analysis of identified process and effluents streams throughout the plant. The system monitors the radiation levels during normal, abnormal and accident plant conditions. The stack vent discharge and the standby gas treatment system (SGTS) are both equipped with high range detectors for post accident monitoring of levels up to 10 uc/cc.

The process and effluent paths and/or areas as described herein are monitored for potential high radioactivity releases. The monitoring channels of items 1 through 4 below are provided for safety as Class IE instrumentation, while the rest of the process radiation instrumentation is considered non-essential which is provided to monitor plant operations.

(1) Main steam line (MSL) tunnel area - 4 divisional channels

The MSL tunnel area is continuously monitored for high gross gamma radioactivity in the steam flow to the turbine. Reactor scram, MSIV closure, and main condenser vacuum pump shutdown are automatically initiated on any two out of four channel trip.

(2) Reactor Building ventilation exhaust - 4 divisional channels

The air vent exhaust from the secondary containment is continuously monitored for gross gamma radioactivity. On high level, the standby gas treatment system is activated and the containment ventilation ducts are isolated on any two out of four channel trip.

(3) Fuel handling area ventilation exhaust - 4 divisional channels

The air vent exhaust from the fuel handling area is continuously monitored for gross gamma radioactivity. On high level, the standby gas treatment system is activated and the fuel handling area ventilation ducts are isolated on any two out of four channel trip.

(4) Control Building air intake supply - 4 divisional channels

The air intake to the Control Building is continuously monitored for gross gamma radioactivity. On high level, the ventilation ducts are isolated and the emergency air circulation system is activated on any two out of four channel trip.

(5) Turbine Building ventilation exhaust - 4 channel

The vent exhaust from the Turbine Building is continuously monitored for gross gamma radioactivity. The air exhaust from the equipment compartment area and from the clean areas in the Turbine Building are each monitored by two redundant channels. Alarms are initiated on high radiation levels.

(6) Charcoal vault ventilation exhaust - 1 channel

The vent exhaust from the charcoal vault is continuously monitored for gross gamma radioactivity that may result from cracks in the activated charcoal beds. An alarm is initiated on high radiation.

(7) Pre-treated main condenser off-gases - 1 channel

The pre-treated main condenser off-gases are continuously sampled and monitored for gross gamma radioactivity. Alarms are initiated on high radiation and on abnormal sampling flow. Vial sampling is provided for periodic isotopic analysis.

(8) Post treated main condenser off-gases - 2 channels

The treated off-gases are continuously sampled and monitored for airborne radioactivity by two gas samplers and filters for collecting air particulates and halogens. Each gas sampler consists of a beta/gamma sensitive detector and a source check for periodic testing. On high radiation, the off-gases are routed through the entire charcoal bed for hold-up. On extremely high radiation, the off-gas discharge to the stack is isolated. Alarms are initiated on high radiation levels and on abnormal sampling flow. Vial sampling is provided for periodic isotopic analysis.

(9) Plant vent discharge - 2 channels

The discharge through the stack is continuously sampled through an isokinetic probe and monitored for airborne radioactivity by two redundant channels, each consists of a beta/gamma sensitive detector with a source check, a high-range ion chamber, and filters for collecting air particulates and halogens. Sampling and collecting of tritium is also provided. Alarms are initiated on high radiation levels and on abnormal sampling flow.

(10) Radwaste Building ventilation exhaust - 1 channel

The air vent exhaust from the Radwaste Building is continuously sampled through an isokinetic probe and monitored for airborne radioactivity by a beta/gamma sensitive detector with a source check and filters for collecting air particulates and iodine. A tritium monitor is also provided for sample collection. Alarms are initiated on high radiation and on abnormal sampling flow.

(11) Radwaste liquid discharge - 1 channel

The liquid waste discharge from the plant is continuously sampled and monitored by a liquid sampler, which consists of a scintillation detector, a source check and an ultra sonic cleaner. Alarms are initiated on high radiation levels and on abnormal sampling flow. On high radiation in the discharged waste, the flow to the environment is automatically terminated and alarmed.

(12) Drywell sump liquid discharge - 2 channels, one per sump

The liquid discharge from each of the two drywell sumps is monitored by an in-line ion chamber. On high radiation, the discharge to the Radwaste Building is terminated and alarmed.

(13) Standby gas treatment system (SGTS) discharge - 4 channels

The discharge from the SGTS to the stack is continuously sampled and monitored for airborne radioactivity by two gas chambers that are in series with the flow and by sampling filters for collecting air particulates and halogens. Each gas sampler consists of a scintillation detector and a source check. Also, radioactivity in the discharged gases are continuously monitored for gamma radiation by two in-line high-range ion chambers. Alarms are initiated on high radiation levels.

(14) Turbine gland steam condenser discharge - 1 channel

The discharge from the main turbine gland steam condenser is continuously sampled and monitored for airborne radioactivity by a gas chamber and by sampling filters for collecting air particulates and halogens. The gas sampler consists of a scintillation detector and a source check for periodic testing of the detector. Vial sampling is provided for laboratory analysis. Alarms are initiated on high radiation levels.

(15) Intersystem radiation leakage - 3 channels, one per RCW system loop

Intersystem leakage into each loop of the reactor building closed cooling water system is monitored by an in-line scintillation detector for gross gamma radioactivity. An alarm is initiated on high radiation.

Location of the process radiation monitors is shown in the plant layout drawing of Figure 2.3.1 The radiation detectors are numbered according to the listing provided above.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.3.1 provides a definition of the inspections, tests and/or analyses together with the associated acceptance criteria which will be undertaken for the Process Radiation Monitoring System.

2.3.1

Table 2.3.1: Process Radiation Monitoring (PRM) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The PRM is designed to continuously monitor the radiation levels in process and effluent liquid and gaseous streams throughout the plant.	1. Each detector shall be checked for sensitivity and calibration based on certified records and/or response tests using either a portable gamma source or the detector check source as required. Each radiation monitor shall be visually checked for operational readiness.	1. Proper detector calibration and sensitivity are verified based on acceptable records and/or test results. Operational readiness of each radiation monitor is verified by the monitor self test circuitry.
2. The PRM is designed to initiate automatically the controls and safety actions as required to isolate and prevent further releases of radioactivity.	2. The range of each radiation channel shall be checked for the correct response using sufficient simulated inputs. Also, the trip levels that initiate the safety actions and plant controls shall be verified.	2. Verification that the correct monitor response is indicated at the specified inputs for each channel. Also, confirmation that the trips are initiated at the proper setpoints.
3. Each process radiation monitors is designed to initiate alarms on high and low radiation levels and when the monitor indicates gross failure (INOP trip).	3. The alarm setpoints of each radiation channel shall be verified using the adjustable trip output circuits and the INOP trip feature of the monitor.	3. Confirmation that alarm initiation occurs at the proper setpoint and when the monitor indicates gross failure.
4. The PRM is used to monitor radiation levels during normal, abnormal and accident plant conditions.	4. Verify that the high range monitors of the plant vent discharge and the SGTS can detect gaseous effluents of levels up to 10^5 uc/cc.	4. Verification that each high range monitoring channel including the associated radiation monitor is capable of satisfying this requirement.
5. The PRM samples and monitor effluents for noble gases and for collecting air particulates, halogens and vial samples.	5. Verify that the sampling racks and associated equipment are operating within specified limits to assure the extraction of valid and representative samples.	5. Operation of the sample racks is verified when the extracted air flow is normal and is within acceptable limits.
6. For the safety related functions, the PRM provides 4 redundant divisional channels to initiate the required protective action on two out of four channel trip.	6. Each required safety function shall be tested using various simulated signal inputs to verify that the initiation of the protective action occurs only when any two out of four channels indicate trip.	6. Acceptance is based on satisfying the two out of four criteria for initiating the required functions.

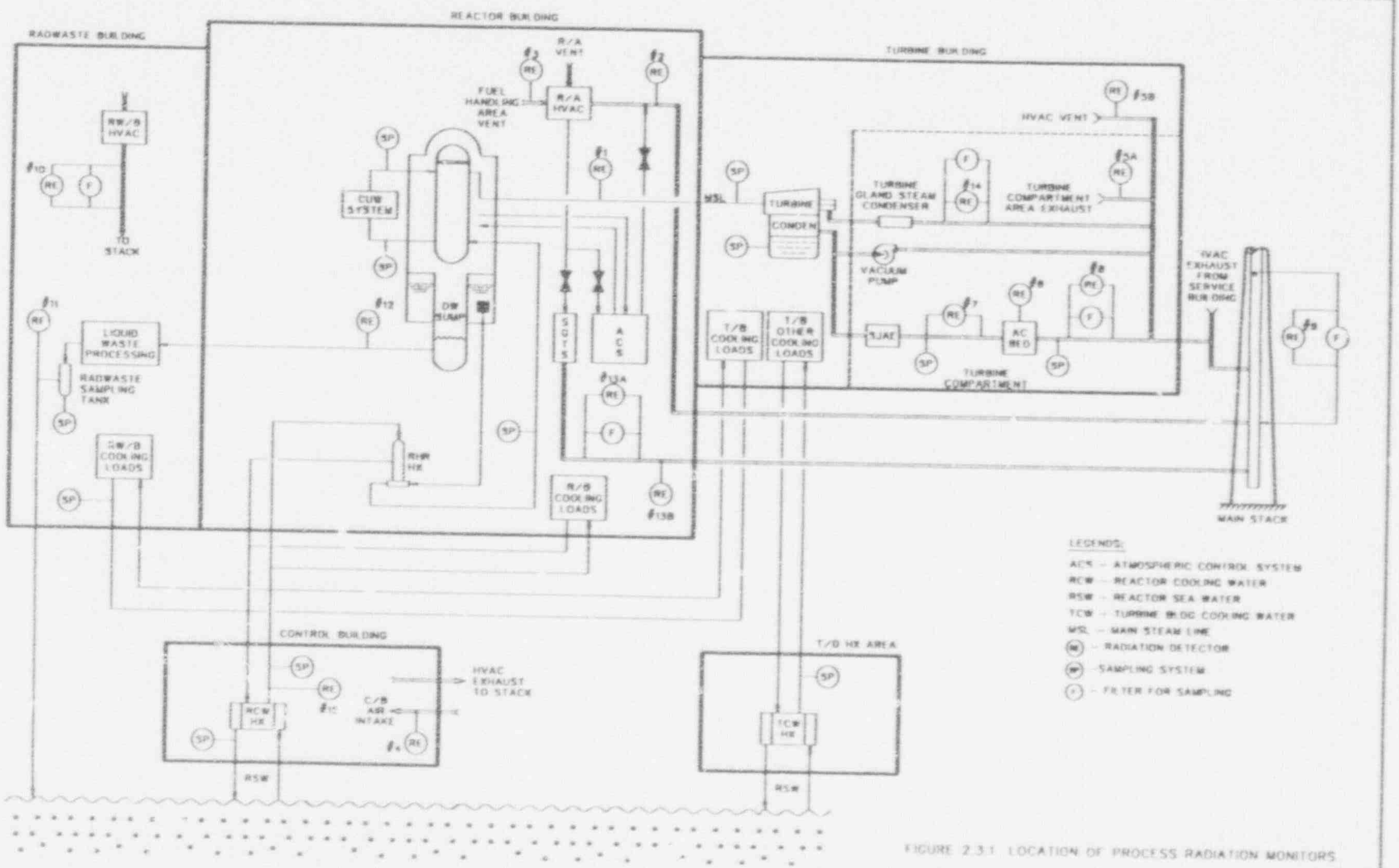


FIGURE 2.3.1 LOCATION OF PROCESS RADIATION MONITORS

Figure 2.3.1 Location of Process Radiation Monitors

2.3.2 Area Radiation Monitoring System

Design Description

The primary function of the Area Radiation Monitoring (ARM) System is to monitor continuously gamma radiation levels at various locations within the plant buildings, and to provide early warning to plant personnel when high radiation levels are detected so that appropriate actions can be taken to reduce further exposure to radiation.

The ARM System consists of local area radiation detectors, digital radiation monitors, and local auxiliary units with audible alarms installed in selected key areas. Each instrumented channel provides trips on high radiation level, lack of detector response, and on gross failure of the monitor. Alarms are activated on abnormal indications in the main control room (MCR) as well as in the local areas where the sonic alarms are provided.

The gamma radiation level is continuously monitored and recorded in each area where installed. An increase in background radiation level is normally attributable to either operational transients, maintenance activities, or to inadvertent release of radioactivity.

The instrumentation channels of the area radiation monitoring system are designed to detect exposure rates from 10^{-2} mR/hr to 10^{4} R/hr during reactor operation and during abnormal and accident conditions. The measuring range and sensitivity of each channel are based on the expected background radiation level at the location where the detector is installed.

The alarm trip setpoint for each channel is adjustable and will be based on the actual background radiation level measured at the detector location.

The system is classified as non-safety related. Power to the radiation monitors is provided from the 125VAC non-essential vital source, which is available during loss of off-site power.

The system design is configured as shown in Figure 2.3.2.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.3.2 provides definition of the inspections, tests, and/or analysis together with associated acceptance criteria which will be undertaken for the ARM System.

Table 2.3.2a: D21 Area Radiation Monitoring System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The instrumented area radiation monitoring system channels are designed to measure and record the gamma radiation levels at various locations in each of the plant buildings.	1. Visually inspect and verify that the equipment for each instrumented channel is properly configured, installed and functional.	1. Verification that each channel configuration is in conformance with the required design. Also, that operational readiness of each channel is verified when indicated on the monitor.
2. Each channel measures and displays the gamma dose rate across its monitoring range and provides dosage level indications in the main control room.	2. Each channel shall be tested across its monitoring range to verify response, sensitivity, and calibration by using a portable gamma source traceable to the NBS.	2. Successful channel operation will be demonstrated when the radiation monitor indicates proper response and displays the measurement within the required accuracy.
3. Each channel activates alarms in the MCR and at local areas on indication of high radiation, lack of detector response, and inoperative radiation monitor.	3. The alarm trip setpoints of each channel shall be tested and validated. Initiation of the appropriate alarms in the MCR and in local areas shall be verified.	3. Initiation of the appropriate alarms is confirmed at the required trip setpoints.

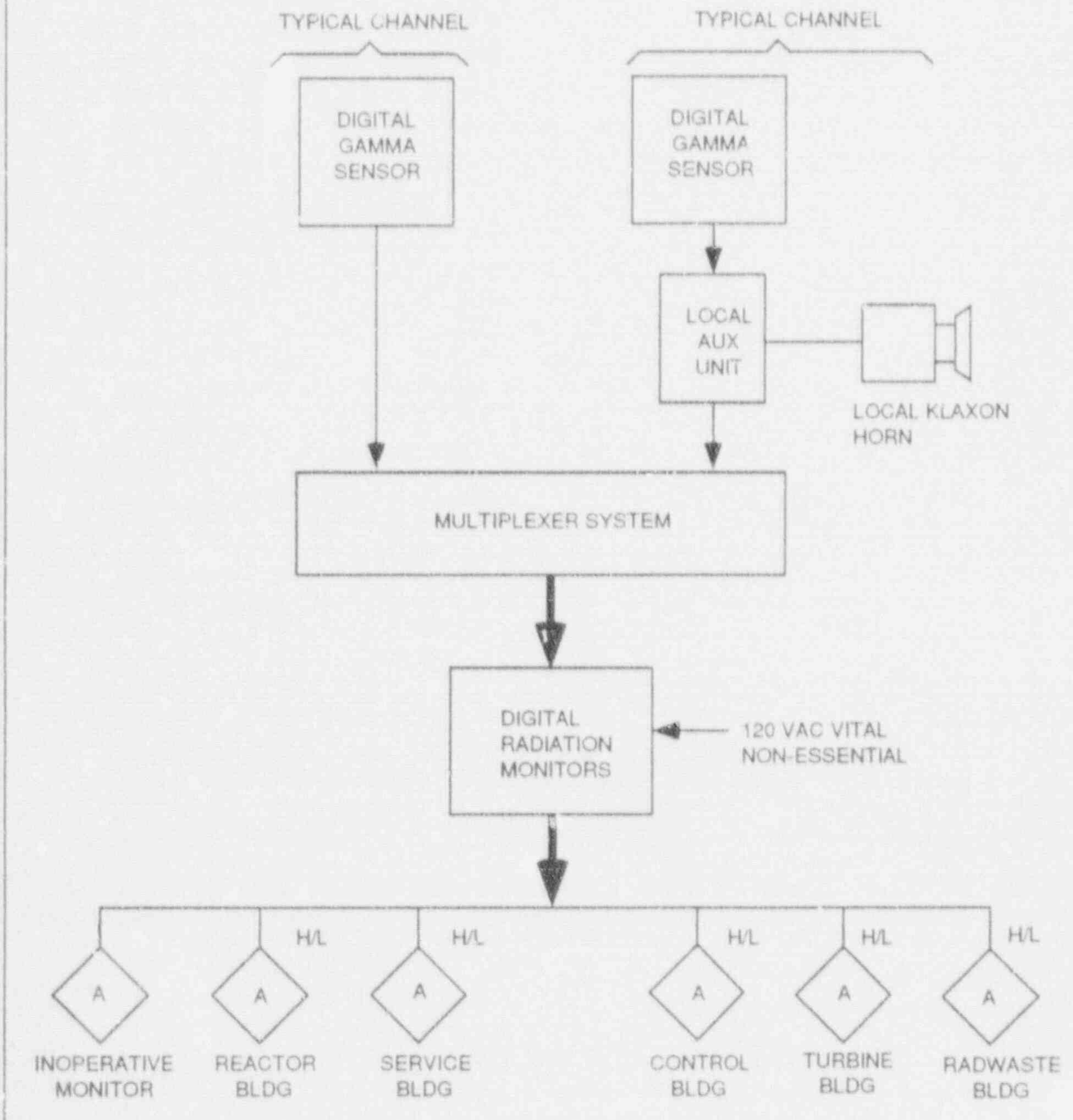


Figure 2.3.2 Area Radiation Monitoring System

2.3.3 Dust Radiation Monitoring System

Not an ABWR system. No entry.

2.3.4 Containment Atmospheric Monitoring System

Design Description

The primary function of the Containment Atmospheric Monitoring (CAM) System is to monitor the atmosphere in the primary containment for excessive gamma radiation levels and for high concentration of oxygen and hydrogen levels during normal reactor operations and under post-accident conditions. The CAM System is classified as a safety system, seismic Category I, and provides no control function.

The safety function of the CAM System is to identify if a potentially explosive mixture of hydrogen and oxygen is building up in the primary containment during post-accident monitoring, and provide concentration measurements to the operator for use in flammability control. Also, the use of gamma monitors with high-range are provided for post-accident monitoring.

The CAM System consists of two independent but redundant divisional subsystems (I and II), which are electrically and physically separated (Figure 2.3.4). Each CAM division provides measurement of the total gamma-ray dose rate and of the concentration of hydrogen and oxygen levels in the drywell and/or the suppression chamber during normal plant operation and following a LOCA event.

The operation of each CAM Subsystem can be activated manually by the operator during reactor operations, or it will be automatically activated by the LOCA signal, either on high drywell pressure or on low reactor water level. In either mode, sampling is selected for the designated area.

Two high-range radiation monitoring channels are provided per division, one for monitoring the radiation level in the drywell and the other for monitoring the radiation level in the suppression chamber. Each channel provides continuous dosage rate measurements for display and recording in the control room. Alarms are activated on high radiation levels and when the monitors fail and become inoperative. Each monitor has a measurement and display range of 1 to 10^7R/hr.

Each divisional hydrogen/oxygen monitoring channel consists of a gas sampling rack used to extract samples of the atmosphere in the drywell (DW) or the suppression chamber (SC) and feeds the sample to a local gas analyzer for measurement and display in the control room. Alarms are activated on high gas content levels and for abnormal flow sampling. Each gas sampling rack is provided with gas calibration sources to verify operability of the individual gas monitors and for periodic calibration. Each hydrogen and oxygen monitor is capable of measuring gas contents up to 30% of volume and displays digitally the readout.

Power to each CAM subsystem is provided from the uninterruptable Class 1E 120 VAC vital divisional source.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.3.4 provides a definition of the inspections, tests, and/or analysis, together with associated acceptance criteria which will be undertaken for the Containment Atmospheric Monitoring System.

Table 2.3.4: Containment Atmospheric Monitoring System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Each CAM subsystem is designed to be operated manually. Air sampling and radiation monitoring are performed to check and analyze the air in the primary containment for high levels of gas concentrations and radiation.	1. Manually activate each subsystem and verify operational readiness of the radiation monitors and the sampling equipment. Select an air sample from the DW and SC, verify alignment of the sample lines control valves, and check for normal air flow.	1. Equipment readiness will be verified when each radiation monitor and each sampling rack correctly indicates no failure and are ready for operation. Correct valve alignment and normal air sampling will be indicated by the instrumentation.
2. Each CAM subsystem is designed to be activated automatically by a LOCA signal for post-accident monitoring of the same parameters as identified under item #1 above.	2. In the auto mode, use simulated LOCA signals to initiate operation of each CAM subsystem and verify the sampling and monitoring operations for the conditions stipulated in item #1 above.	2. Equipment readiness will be verified when the same conditions stipulated under item #1 above are satisfied.
3. Each radiation channel monitors and displays the gamma dosage rate in the MCR in R/hr, and activates alarms on high radiation levels or when the monitor fails.	3. Each channel shall be tested to verify channel response and measurement by using a portable gamma radiation source. Tests shall be performed at least one point at low end of the monitor range to verify channel response and sensitivity. Perform trip tests to validate the setpoints.	3. Successful channel operation will be verified when each monitor provides the required response and displays the sensed radiation level and initiates the appropriate alarms.
4. Each CAM System gas sampler extracts an air sample from the DW or the SC, analyzes the hydrogen contents and displays the measurement in the MCR in percent volume. High gas levels and abnormal sampling will be alarmed in the MCR.	4. Each hydrogen monitor shall be tested at least two known H_2 concentration levels from 1 to 5 percent content using a hydrogen gas calibrated source. The channel response and readout shall be verified. Perform trip tests for setpoint verification.	4. Monitor operability will be verified when the response and display are compatible with the tested gas levels. Confirmation that the MCR alarms are initiated.
5. Each CAM System gas sampler extracts an air sample from the DW or the SC, analyzes the contents for oxygen and displays the results in the MCR in percent volume. High gas levels and abnormal sampling will be alarmed.	5. Each oxygen monitor shall be tested at least one known O_2 concentration level from 1 to 5 percent content using an oxygen gas calibration source. The channel response and readout shall be verified. Perform trip tests to verify the setpoints.	5. Monitor operability will be verified when the response and display are compatible with the tested gas levels. Confirmation that the MCR alarms are initiated.

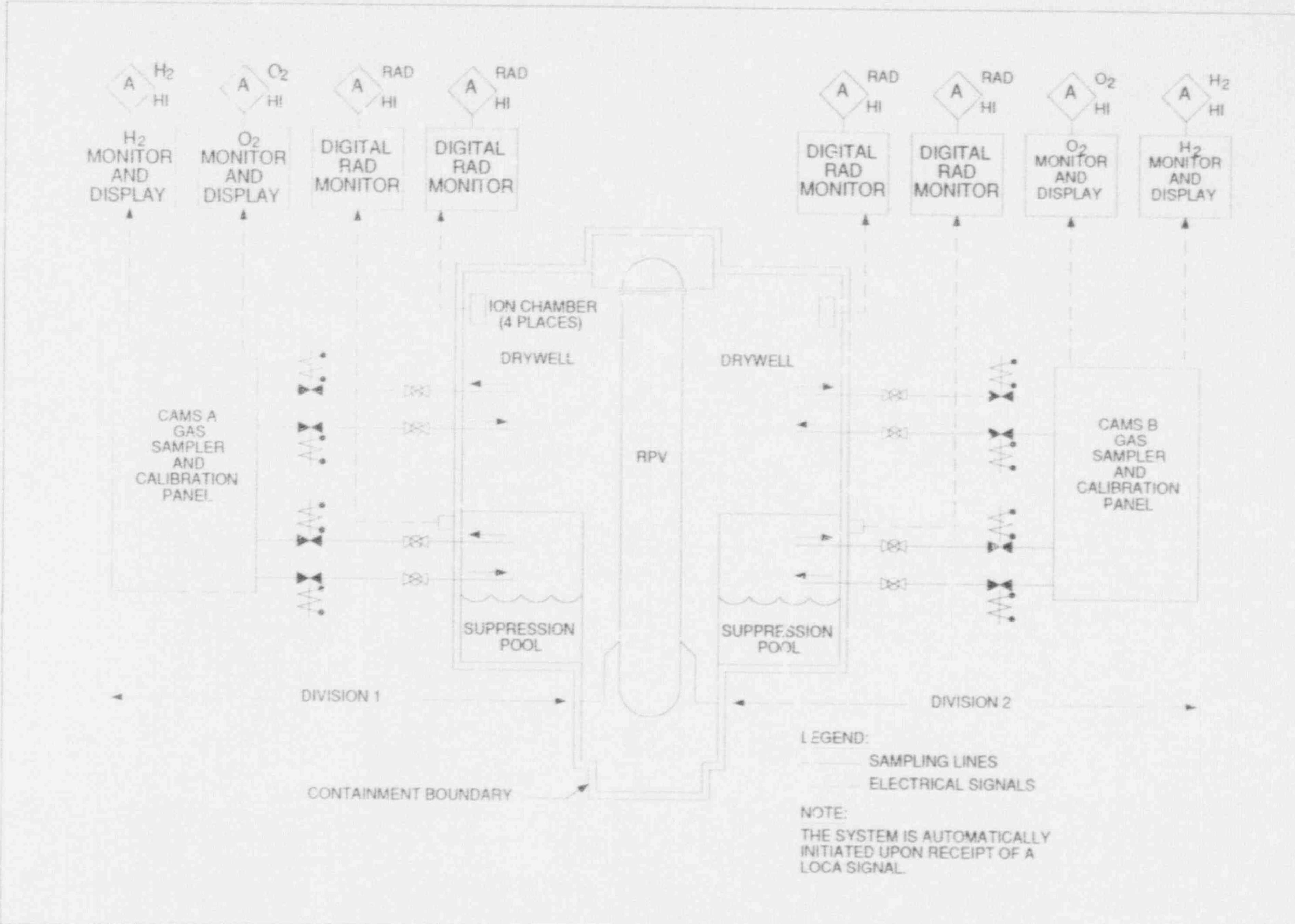


Figure 2.3.4 Containment Atmospheric Monitoring System

2.4 CORE COOLING

2.4.1 Residual Heat Removal System

Design Description

The Residual Heat Removal (RHR) System is comprised of three divisionally separate subsystems that perform a variety of functions utilizing the following six basic modes of operation: (1) shutdown cooling, (2) suppression pool cooling, (3) wetwell and drywell spray cooling, (4) low pressure core flooder (LPFL), (5) fuel pool cooling, and (6) AC independent water addition. The configuration of each loop is shown on its P&ID in Figure 2.4.1 (aligned in the standby mode). The major functions of the various modes of operation include: (1) containment heat removal, (2) reactor decay heat removal, (3) emergency reactor vessel level makeup and (4)augmented fuel pool cooling. In line with its given functions, portions of the system are a part of the ECCS network and the containment cooling system. Additionally, portions of the RHR System are considered a part of the Reactor Coolant Pressure Boundary (RCPB).

The entire RHR System is designed to safety-related standards, although it performs some non-safety functions (i.e., those that are not taken credit for when evaluating design basis accidents). The safety-related modes of operation include: (1)low pressure flooding, (2)suppression pool cooling, (3) wetwell spray cooling and (4)shutdown cooling. Non-safety-related modes of operation include: (1)drywell spray cooling, (2)AC independent water addition and (3)augmented fuel pool cooling. The RHR System also provides a backup, safety-related fuel pool makeup capability. Ancillary modes of operation include minimum flow bypass and full flow testing.

The ECCS function of the RHR System is performed by the LPFL mode. Following receipt of a LOCA signal (low reactor water level or high drywell pressure), the RHR System automatically initiates and operates in the LPFL mode (in conjunction with the remainder of the ECCS network) to provide emergency makeup to the reactor vessel in order to keep the reactor core cooled such that the criteria of 10 CFR 50.46 are met. The LPFL mode is accomplished by all three loops of the RHR System by transferring water from the suppression pool to the RPV, via the RHR heat exchangers. Although the LPFL mode is automatically initiated , it may also be initiated manually. The system will also automatically revert to the LPFL mode of operation from any other test or operating mode upon receipt of a LOCA signal. Each RHR loop's RPV injection valve requires a low reactor pressure permissive signal whether being opened manually or automatically in response to a LOCA signal.

The containment heat removal function in the ABWR is performed by the Containment Cooling System, which is comprised of the low pressure core flooder (LPFL), suppression pool cooling, and wetwell and drywell spray cooling modes of the RHR System. Following a LOCA, the energy present within the reactor primary system is dumped either directly to the suppression pool via the SRVs, or indirectly via the drywell and connecting vents. Subsequently, fission product decay heat continues to add energy to the pool. The Containment Cooling System is designed to limit the long-term bulk temperature of the suppression pool, and thus limit the long-term peak temperatures and pressures within the wetwell and drywell regions of the containment to within their analyzed design limits, with only two of the three loops in operation (i.e., worse case single failure). The cooling requirements of the containment cooling function establish the necessary RHR heat exchanger heat removal capacity.

The LPFL mode, in addition to its primary function of cooling the core, serves to cool the containment, as the heat exchanger is designed to always be in the loop. The dedicated suppression pool cooling mode is made available in each of the three loops of the RHR System by circulating suppression pool water through the respective RHR heat exchanger and then directly back to the suppression pool. This mode of RHR is usually initiated manually but will also initiate automatically in response to high suppression pool temperature. The wetwell and drywell spray modes of RHR are each available in only two of the three subsystems (loops B and C). These functions are performed by drawing water from the suppression pool and delivering it to a common wetwell spray header and/or a common drywell spray header both via the associated RHR heat exchanger(s). These containment spray modes of the RHR System are typically initiated manually, with the exception of automatic initiation of wetwell spray coincident with automatic suppression pool cooling. However, the drywell spray inlet valves can only be opened if there exists high drywell pressure and if the RPV injection valves are fully closed. Wetwell and drywell sprays serve as an augmented method of containment cooling. Wetwell spray also serves to mitigate the consequences of steam bypassing the suppression pool.

The normal operational mode of the RHR System is in the shutdown cooling mode of operation, which is used to remove decay heat from the reactor core. This mode provides the required safety-related capability needed to achieve and maintain a cold shutdown condition, including consideration of the worst case system single failure. The RHR heat exchanger heat removal capacity requirements in this mode are bounded by containment cooling requirements. Shutdown cooling is initiated manually once the RPV has been depressurized below the system low pressure permissive. In this mode each loop takes suction from the RPV via its dedicated suction line, pumps the water through its respective heat exchanger, and returns the cooled water to the RPV. Two loops (B and C) discharge water back to the RPV via dedicated spargers, while the third loop (A) utilizes the vessel spargers of one of the two feedwater lines (FW-A). The heat removed in the RHR heat exchangers is transported to the ultimate heat sink via the respective division of reactor cooling water and service water. Each shutdown cooling suction valve is interlocked with that loop's suppression pool suction and discharge valves and wetwell spray valve to prevent draining of the reactor vessel to the suppression pool. Also, each shutdown cooling suction valve is interlocked with, and automatically closes on, low reactor water level.

The augmented fuel pool cooling mode of the RHR System supplements/ replaces the normal fuel pool cooling system during infrequent conditions of high heat load. This mode is accomplished manually in one of two ways. When the reactor vessel head is removed, the cavity flooded and the fuel pool gates are removed, the RHR System cools the fuel pool in the normal shutdown cooling mode. When the fuel pool is otherwise isolated from the reactor cavity, two loops (B and C) of the RHR System can directly cool the pool by taking suction from and discharging back to the normal fuel pool cooling system. This connection also provides for emergency fuel pool makeup capability by supplying a safety-related makeup path to the fuel pool from a safety-related source (i.e., the suppression pool).

One loop (C) of the RHR System also functions in an AC independent water addition mode. This mode provides a means of cross connecting the reactor building fire protection system header to the RHR System just outside the containment in the absence of the normal ECCS network and independent of the normal essential AC power distribution network. The connection is accomplished by manually opening two in-series valves on the cross-connection piping just upstream of its tie-in to the normal RHR piping. Fire protection system water can be directed to either the RPV or the drywell spray sparger by manual opening of the loop C RHR injection valve or the two loop C drywell spray valves. These three valves also have manual hand wheels. The fire water is supplied via the system's reactor building distribution header by either the direct diesel-driven fire pump or from an external source utilizing a dedicated connection just outside the reactor building.

Each loop of the RHR System also has both a minimum flow mode and a full flow test mode. The minimum flow mode assures that there is pump flow sufficient to keep the pump cool by opening a minimum flow valve that directs flow back to the suppression pool anytime the pump is running and the main discharge valve is closed. Upon sensing that there is adequate flow in the pump main discharge line, the minimum flow valve is automatically closed. In the full flow test mode, the system is essentially operated in the suppression pool cooling mode, drawing suction from and discharging back to the suppression pool.

The RHR System is comprised of three separate loops or subsystems, each of which includes a pump and a heat exchanger, takes suction from either the RPV or the suppression pool, and directs water back to either the RPV or the suppression pool. Two of the three loops can divert a portion of the suppression pool return flow to a common wetwell spray sparger or direct the entire flow to a common drywell spray sparger. The divisional subsystems of the RHR System are separated both mechanically and electrically, as well as being physically located in different areas of the plant to address requirements pertaining to fire protection and other separation criteria. Each of the three subsystems is powered from a separate divisional power distribution bus that can be supplied from either an on-site or off-site source. Cooling water to each division of RHR equipment (heat exchanger as well as pump and motor coolers) is supplied by the respective division of the reactor cooling water (RCW) System. The RHR System also includes provisions for containment isolation and RCPB pressure isolation.

The RHR System will maintain the capability to perform its intended safety-related functions either following a Safe Shutdown Earthquake (SSE) or during the environmental conditions imposed by a LOCA, and in each case assuming the worst case single failure. The system will also accommodate calculated movement and thermal stresses. The system is designed so that the pumps will have necessary head/flow characteristics and available NPSH greater than required NPSH for operating modes. The system can be powered from either normal off-site sources or by the emergency diesel generators. The RHR System is Seismic Category I and is housed in the Seismic Category I reactor building to provide protection against tornadoes, floods, and other natural phenomena.

The RHR pumps are motor-driven centrifugal pumps each capable of supplying at least 4200 gpm at 40 psid (drywell to RPV). The pumps are ASME Code Class 2 components with a design pressure of 500 psig and a design temperature of 360°F. The pumps are interlocked from starting without an open suction path. The RHR pumps are protected from possible pump run-out conditions during operation. The RHR heat exchangers are horizontal U-tube/shell type each sized to provide a minimum effective heat removal capacity (K-coefficient) of 105 Btu/sec°F. The primary and secondary sides of the heat exchangers are ASME Code Class 2 and 3, respectively. The primary side design temperature and pressure are 500 psig and 360°F, respectively. The secondary side design temperature and pressure are consistent with that of the RCW System. Each loop of the RHR System has its own jockey pump to act as a keep-fill system for that loop's pump discharge piping. The jockey pumps are ASME Code Class 2.

The RHR System piping and valves are ASME Code Class 1 or 2 as shown on the P&ID (Figures 2.4.1a, b, c). The design pressure and temperature of piping and valves varies across the system. For that piping attached to the RPV, from the RPV out to and including the outboard containment isolation valves, the design pressure and temperature are 1250 psig and 575°F, respectively. For other piping open to the containment atmosphere, out to and including the outboard containment isolation valves, the design pressure and temperature are 45 psig and 219°F, respectively. For piping and valves outside the containment isolation valves, the design pressure and temperature depends on whether it is located on the suction or discharge side of the main pump. Those portions on the suction side are rated at 300 psig and 360°F, while those portions on the discharge side are rated at 500 psig and 360°F, respectively. The low pressure portions of the shutdown cooling piping are protected from full reactor pressure by automatic pressure isolation valves that are interlocked with reactor pressure. High reliability of this interlock is assured by utilizing four separate and divisionally independent pressure sensors in a 2-out-of-4 logic. Additionally, in-series inboard and outboard containment/pressure isolation valves in each loop are powered from separate electrical divisions. Relief valves are also provided for protection from overpressure.

The RHR System includes control room indication to allow for monitoring and control during design basis operational conditions, i.e., system flows, temperatures and pressures, as well as valve open/close and pump on/off indication for those instruments and components shown on Figures 2.4.1a, b and c, with the exception of simple check valves and overpressure relief valves (of the check valves shown only the testable check valves downstream of each loop's RPV injection valve has control room status indication).

Inspections, Tests, Analyses and Acceptance Criteria

This section provides a definition of the inspections, tests and/or analyses together with associated acceptance criteria which will be undertaken for the RHR System.

Table 2.4.1: Residual Heat Removal System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the RHR System is shown in Figures 2.4.1a, b and c, which are each mechanically and electrically separated from each other.	1. Inspections of the as-built RHR configuration shall be performed.	1. Actual RHR System configuration, for those components shown, conforms with Figures 2.4.1a, b and c and separation requirements.
2. The RHR System operates in the LPFL mode as part of the overall ECCS network.	2. The ECCS LOCA performance analysis for assuring core cooling shall be validated by RHR System functional testing, including demonstration that the LPFL mode (of each RHR loop) is capable of automatically initiating and operating in response to a LOCA signal.	2. RHR System actuation and operation is consistent with the ECCS performance analysis as follows: a. RHR Flow (each loop) .....≥ 4200 gpm (at 40 psid) b. Time to Rated Flow (each loop) .....≤ 36 sec
3. The RHR System operates in the suppression pool cooling mode to limit the long-term temperature and pressure of the containment under post-LOCA conditions.	3. The primary containment performance analysis for long-term peak pressure and temperature shall be validated by RHR System functional testing demonstrating the required flowrate through the heat exchanger and by inspection of vendor test data demonstrating the heat exchanger's effective heat removal capability. Automatic initiation in the suppression pool cooling mode will also be demonstrated.	3. RHR System automatically actuates in the suppression pool cooling mode as designed and RHR heat exchanger performance is consistent with the containment cooling system analysis as follows: a. Effective heat removal capability of each RHR Heat Exchanger (K coefficient) includes effects of RCW, RSW and UHS: .....≥ 195 Btu/sec°F. b. Tube side flow of each RHR Heat Exchanger .....≥ 4200 gpm
4. A portion of the RHR System return flow (in loops B & C) can be diverted to the wetwell spray header.	4. RHR System functional tests shall be performed to demonstrate wetwell spray flow capability.	4. RHR loops B and C each separately are capable of providing wetwell spray flow consistent with the suppression pool bypass analysis as follows: a. Wetwell spray flow (each loop individually) ....≥ 500 gpm.

Table 2.4.1: Residual Heat Removal System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. The RHR System operates in the shutdown cooling mode to remove reactor core decay heat and bring the reactor to cold shutdown conditions.	5. RHR System functional tests shall be performed to demonstrate operation in the shutdown cooling mode of operation.	5. RHR System (each loop) is capable of taking suction from and discharging back to the reactor pressure vessel. [Heat exchanger heat removal capability in this mode is bounded by containment cooling requirements - ITAAC # 3]
6. The RHR System (loops B and C) operates in the augmented fuel pool cooling mode to supply supplemental or replacement cooling to the spent fuel storage pool under abnormal conditions.	6. RHR System functional tests shall be performed to demonstrate operation in the augmented fuel pool cooling mode of operation.	6. RHR System (loops B & C) is capable of taking suction from and discharging back to the normal fuel pool cooling system. [Required cooling capability in this mode bounded by containment cooling requirements - ITAAC #3]
7. The RHR System (loop C) provides an AC independent water addition function.	7. RHR System functional testing shall be performed to demonstrate operation in the AC independent water addition mode of operation.	7. Flow capability exists for directing water from the fire protection system to the RPV and drywell spray sparger, via the RHR System (loop C), without power being available from the essential AC distribution system. The valves are capable of being opened by manual hand wheels.
8. The RHR System operates when powered from both normal off-site and emergency on-site sources.	8. RHR System functional tests shall be performed to demonstrate operation when supplied by either normal off-site power or the emergency diesel generator(s).	8. RHR System is capable of operating when supplied by either power source.
9. If already operating in any other mode, the RHR System automatically reverts to the LPFL mode in response to a LOCA signal.	9. Using simulated inputs, logic and functional testing shall be performed to demonstrate the RHR System's ability to automatically revert to the LPFL mode from any other mode.	9. RHR logic functions to automatically reconfigure the system to the LPFL mode of operation in response to a LOCA signal.
10. Pressure isolation valves are provided to protect low pressure RHR piping from being subjected to excessively high reactor pressure.	10. Using simulated inputs, logic and functional testing shall be performed to demonstrate operation of automatic isolation and interlock functions of pressure isolation valves.	10. Automatic isolation and interlock features function upon receipt of input signals.

Table 2.4.1: Residual Heat Removal System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
11. Each RHR loop operates automatically in a minimum flow mode to protect the pump from overheating.	11. Logic and functional testing shall be performed to demonstrate operation of the minimum flow mode for each loop (including extended minimum flow operational conditions).	11. RHR System logic functions automatically to assure a pump minimum flow path exists and no deleterious effects are observed during extended operation in the minimum flow mode.
12. The RHR System automatically isolates shutdown cooling suction valves to prevent draining of the reactor vessel.	12. Using simulated inputs, logic and valve functional testing shall be conducted to demonstrate operation of the shutdown cooling mode isolation function.	12. The shutdown cooling suction isolation valves automatically isolate on a low reactor water level signal.
13. RHR System valve interlocks prevent establishment of a drainage path from the reactor vessel to the suppression pool.	13. Using simulated inputs, logic and functional testing shall be conducted to demonstrate operation of interlocking between RPV suction valves and other RHR valves providing potential flow paths to the suppression pool.	13. RHR System valve interlock logic functions upon receipt of input signal
14. The drywell spray inlet valves can only be opened if there exists high drywell pressure and the RPV injection valves are fully closed.	14. Using simulated inputs, logic and functional testing shall be conducted to demonstrate operation of drywell spray permissive logic.	14. RHR drywell spray permissive logic functions to prevent drywell spray inlet valves from opening in the absence of either a high drywell pressure signal or a signal indicating RHR RPV injection valve(s) not fully closed.
15. The RHR pumps are interlocked from starting without an open suction path.	15. Logic tests shall be conducted to demonstrate that the RHR pumps will not start without an open suction path being available.	15. An RHR pump start signal is not generated in the absence of indication of an open suction path.
16. The RHR System utilizes jockey pumps (1 in each loop) to keep the pump discharge lines filled.	16. Functional tests will be performed to demonstrate the ability of the jockey pump (in each loop) to keep its respective RHR pump discharge line full while in the standby mode.	16. Each jockey pump performs its keep-fill function.

Table 2.4.1: Residual Heat Removal System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
17. The RHR System full flow test mode allows periodic demonstration of RHR capability during normal power operation.	17. Functional tests will be performed to demonstrate operation in the full flow test mode.	17. Each RHR subsystem demonstrates full flow functional capability while approximating actual vessel injection conditions during operation in the full flow test mode.
18. The RHR pumps have sufficient NPSH during postulated operating conditions.	18. Pump vendor records will be inspected and as-procured pump NPSH compared with design basis analysis assumptions. Actual system installation will be inspected, and appropriate measurements taken, to determine available pump NPSH.	18. Minimum pump NPSH available, as determined based on as-built conditions and the results of vendor tests and/or analyses, exceeds as-procured pump requirements and is consistent with design basis analyses requirements.
19. The RHR pumps have adequate head/flow characteristics.	19. Pump vendor test records and calculations will be inspected, and as-installed system flow testing conducted, to establish pump head/flow characteristics.	19. RHR pumps, in as-installed system configuration, demonstrate head/flow characteristics consistent with design basis analyses assumptions.
20. Control room indications are provided for RHR System parameters defined in Section 2.4.1.	20. Inspections will be performed to verify presence of control room indication for the RHR System (Section 2.4.1).	20. The instrumentation is present in the control room as defined in Section 2.4.1.

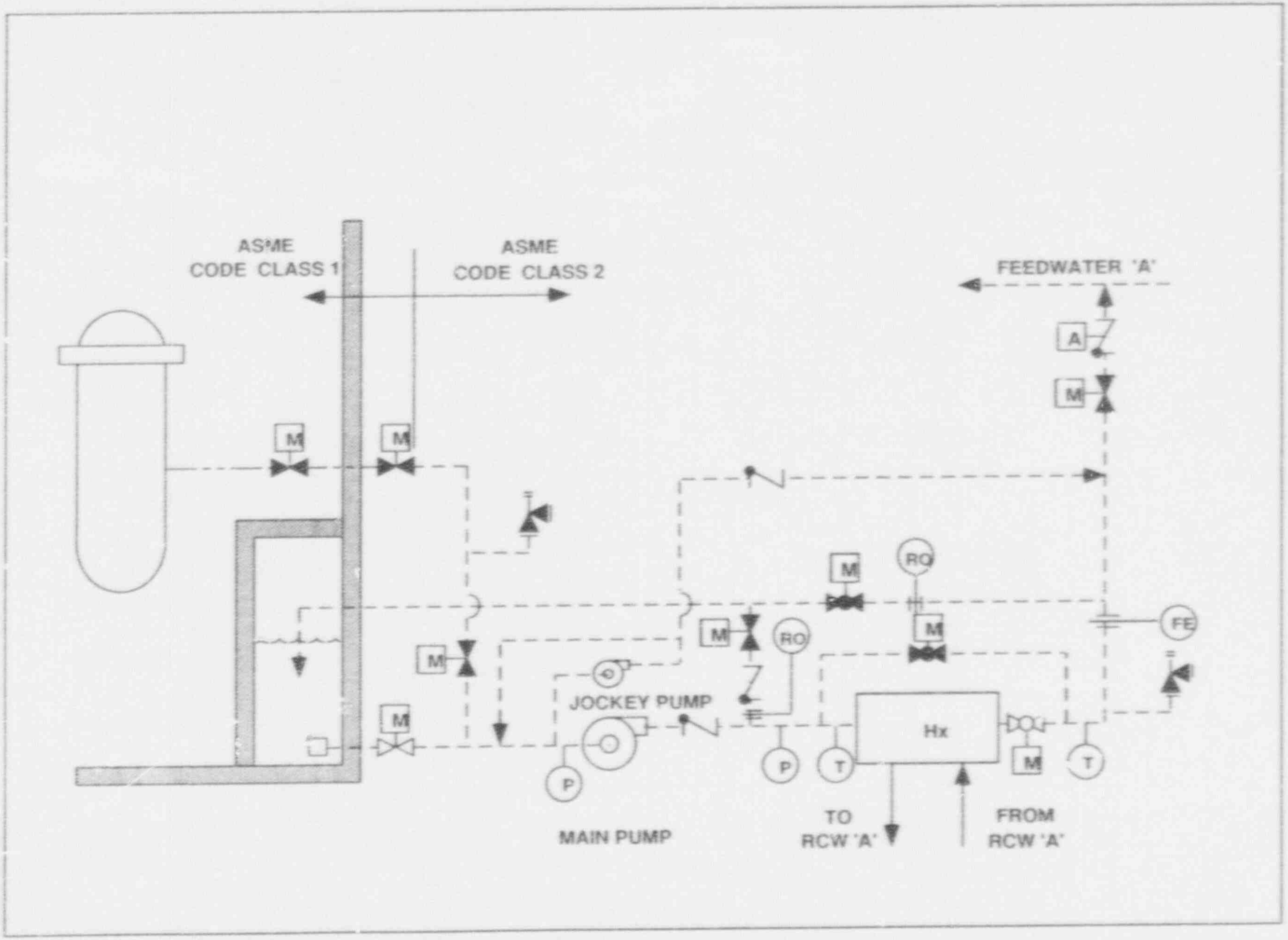


Figure 2.4.1a Residual Heat Removal (RHR-A) System

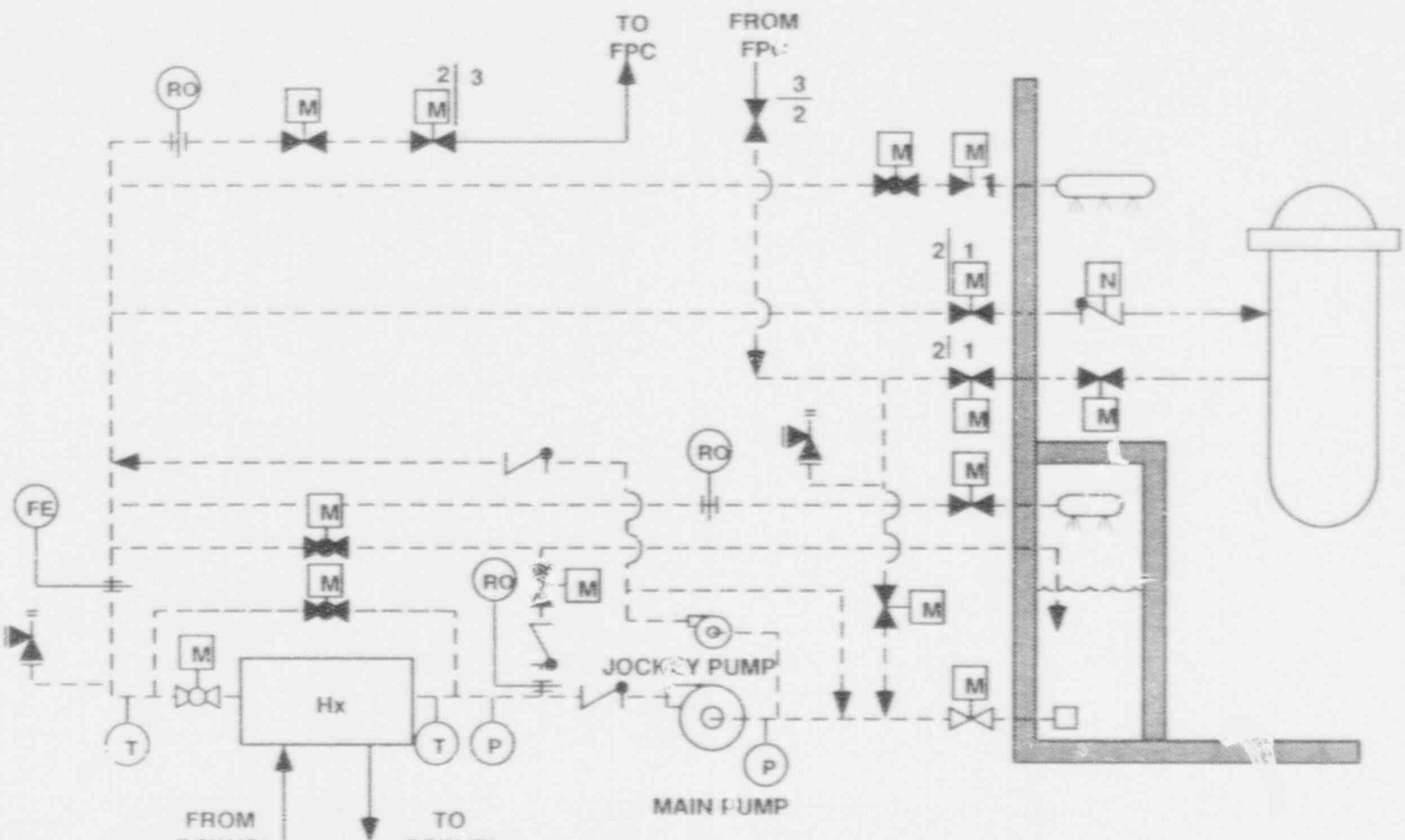


Figure 2.4.1b Residual Heat Removal (RHR-B) System

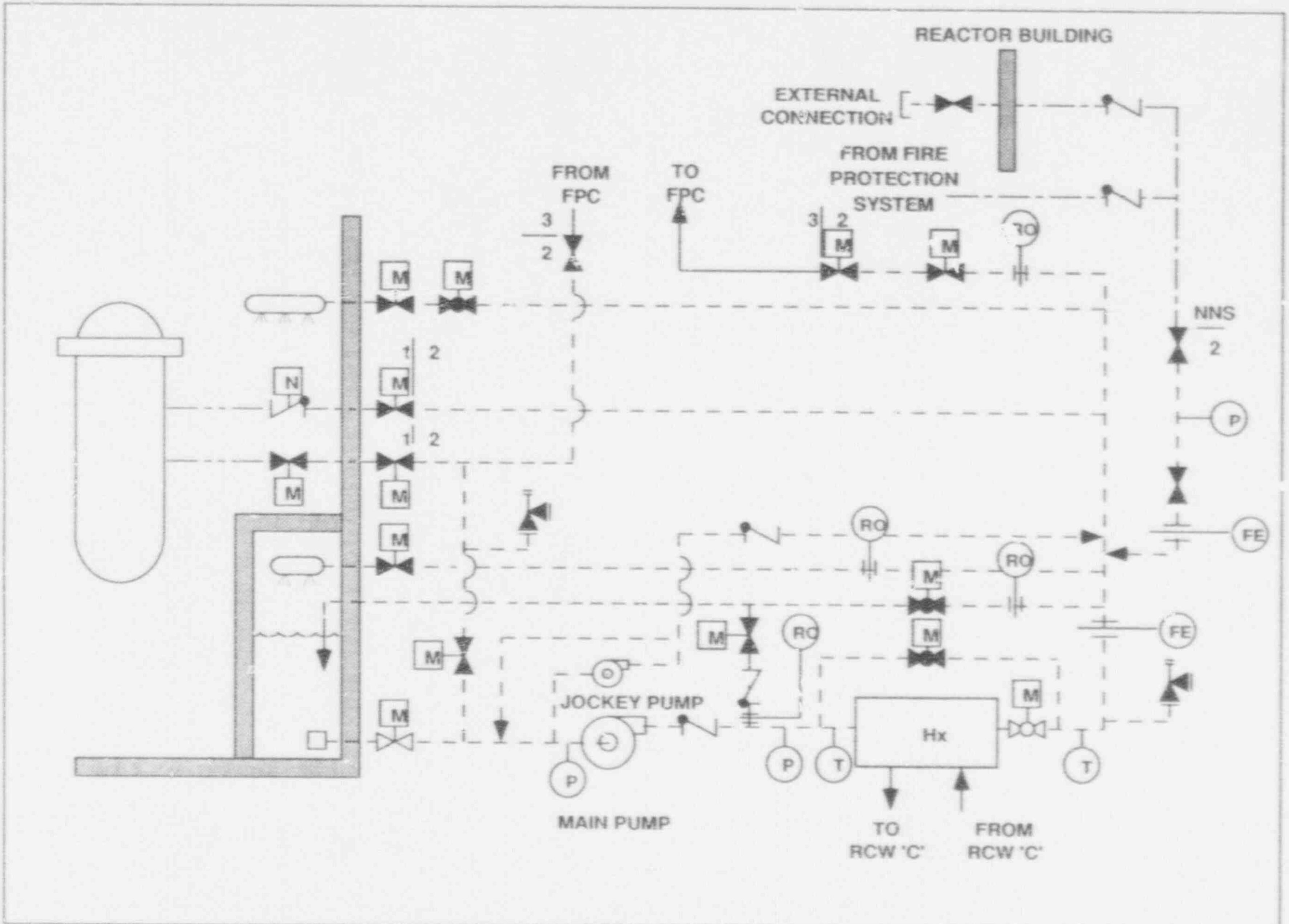


Figure 2.4.1c Residual Heat Removal (RHR-C) System

2.4.2 High Pressure Core Flooder (HPCF) System

Design Description

The High Pressure Core Flooder (HPCF) System is comprised of two divisionally separate subsystems that provide emergency makeup water to the reactor for transient or LOCA conditions. The configuration of each loop is shown in Figure 2.4.2 (aligned in the standby mode). The HPCF System is a part of the ECCS network, and portions of tne system are considered a part of the reactor coolant pressure boundary (RCPB).

The entire HPCF System is designed to safety-related standards. The ECCS function of the HPCF System is performed by the High Pressure Flooder Mode, which floods the core region of the reactor for any reactor pressure condition when an initiation signal is received. Ancillary modes of operation include minimum flow bypass and full flow testing.

Following receipt of an initiation signal (low reactor water level or high drywell pressure), the HPCF System automatically initiates and operates in the flooder mode in conjunction with the remainder of the ECCS network. This emergency makeup to the reactor vessel contributes to keep the reactor core cooled so that the regulatory requirements governing fuel performance during a LOCA are met by the ECCS network. The flooder mode is accomplished by both loops of the HPCF System by transferring water from the Condensate Storage Tank (CST) or the Suppression Pool (S/P) to the RPV. The flooder mode is the only automatically initiated mode of the HPCF System, but it may also be initiated manually. The system will automatically revert to the flooder mode of operation from the test mode upon receipt of an initiation signal.

Each loop of the HPCF System also has both a minimum flow mode and a full flow test mode. The minimum flow mode assures that there is pump flow sufficient to keep the pump cool by opening a minimum flow valve that directs flow back to the S/P anytime the pump is running and the main discharge valve is closed. Upon sensing that there is adequate flow in the pump main discharge line, the minimum flow valve is automatically closed. In the full flow test mode, the system draws suction from the S/P and discharges back to the S/P.

The HPCF System is comprised of two separate loops or subsystems, each of which includes a pump and takes suction from either the CST or the S/P, and directs water back to either the RPV or the S/P. The preferred suction source is the CST. Automatic suction transfer from the CST to the S/P occurs with a CST low water level signal or with a S/P high water level signal. The divisional subsystems of the HPCF System are separated both mechanically and electrically, as well as being physically located in different areas of the plant to address requirements pertaining to fire protection and other separation criteria. The HPCF System is separated both physically and electrically from the RCIC System.

Each of the two subsystems is powered from a separate Class 1E divisional power distribution bus that can be supplied from either an on-site or off-site source. Cooling water to each division of the HPCF pump and motor coolers is supplied by the respective division of the reactor cooling water (RCW) System. The HPCF System also includes provisions for containment isolation and RCPB pressure isolation.

The HPCF System will maintain the capability to perform its intended safety-related functions either following a Safe Shutdown Earthquake or during the environmental conditions imposed by a LOCA, and in each case assuming the worst case single failure. The system will also accommodate calculated movement and thermal stresses. The system is designed so that available NPSH exceeds required NPSH for the pumps in all operating modes. The system can be powered from either normal off-site sources or by the emergency diesel generators. The HPCF System is Seismic Category I and is housed in the Seismic Category I reactor building to provide protection against tornadoes, floods, and other natural phenomena.

The HPCF pumps are motor-driven centrifugal pumps capable of supplying pressure at flow conditions at least equal to or greater than the value corresponding to a straight line between a reactor pressure of 1177 psid at 800 gpm and at a reactor pressure of 100 psid at 3200 gpm. The 1177 and 100 psid pressures are taken between the vessel and the air space of the compartment containing the source water for the pump. The pumps are ASME Code Class 2 components with a design pressure of 1565 psig and a design temperature of 212°F. The pumps are interlocked from starting without an open suction path. The HPCF pumps are protected from possible pump run-out conditions in all operating modes. Each loop of HPCF utilizes a connection from the Makeup Water System (Condensate) (MUWC), which remains open throughout plant operation to serve as a keep-fill system for that loop's pump discharge piping.

The HPCF System piping and valves are ASME Code Class 1 or 2 as shown on Figure 2.4.2. The design pressure and temperature of piping and valves varies across the system. For that piping attached to the RPV, from the RPV out to the containment side (downstream side) of the outboard containment isolation valves, the design pressure and temperature are 1250 psig and 576°F, respectively. The design pressure and temperature for the outboard containment isolation valves are 1565 psig and 576° F, respectively. For other piping open to the containment atmosphere, out to and including the outboard containment isolation valves, the design pressure and temperature are 45 psig and 219°F, respectively. For piping and valves outside the containment isolation valves, the design pressure and temperature depends on whether it is located on the suction or discharge side of the main pump. Those portions on the suction side are rated at 200 psig and 212°F, while those portions on the discharge side are rated at 1565 psig and 212°F, respectively. The low pressure portions of the shutdown cooling piping are protected from full reactor pressure by two check valves in series or combinations of normally closed valves. Relief valves are also provided for protection from overpressure resulting from high pressure valve leakage or water thermal expansion.

The HPCF System includes Control Room indication to allow for the monitoring and control during design basis operational conditions, i.e., system flows and pressures as well as valve open/close and pump on/off indication for those instruments and components shown on Figure 2.4.2, with the exception of simple check valves and overpressure relief valves (of the check valves shown only the testable check valves downstream of each loop's RPV injection valve has control room status indication).

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.4.2 provides a definition of the inspections, tests and/or analyses together with associated acceptance criteria which will be undertaken for the HPCF System.

Table 2.4.2: High Pressure Core Flooder System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The two loop divisional configuration of the HPCF System is shown in Figure 2.4.2, which are each mechanically and electrically separated from each other.	1. Inspections of the as-built HPCF configuration shall be performed.	1. The actual two loop HPCF System configuration, for those components shown, conforms with Figure 2.4.2 and separation requirements.
2. The HPCF System operates in the flooder mode as part of the overall ECCS network.	2. The ECCS LOCA performance analysis for assuring core cooling shall be validated by the HPCF System: a. Demonstration that the flooder mode (of each HPCF loop) is capable of automatically initiating and operating in response to an initiation signal. b. Analyses to demonstrate compliance with acceptance criteria using as-built functional performance test data and construction dimensions.	2. HPCF System actuation and operation is consistent with the ECCS performance analysis as follows: a. HPCF pump developed pressures of at least 1177 psid and 100 psid for flow rates no less than 800 gpm and 3200 gpm, respectively, where the pressure difference is between the RPV and the air space of the compartment containing the source water for the pump, and where the water temperature is valued at 50°F. b. 36 seconds maximum allowed delay time from the initiating signal to rated flow available and the injection valve fully open.
3. The HPCF System operates when powered from both normal off-site and emergency on-site sources.	3. HPCF System functional tests shall be performed to demonstrate operation when supplied by either normal off-site power or the emergency diesel generator(s).	3. HPCF System is capable of operating when supplied by either power source.
4. If already operating in any other mode, the HPCF System automatically reverts to the flooder mode in response to an initiation signal.	4. Using simulated inputs, logic and functional testing shall be performed to demonstrate the HPCF Systems ability to automatically revert to the flooder mode from any other mode.	4. HPCF logic functions to automatically reconfigure the system to the flooder mode of operation upon receipt of an initiation signal.

Table 2.4.2: High Pressure Core Flooder System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. Pressure isolation valves are provided to protect low pressure HPCF piping from being subjected to excessively high reactor pressure.	5. Using simulated inputs, logic and functional testing shall be performed to demonstrate operation of automatic isolation and interlock functions of pressure isolation valves.	5. Automatic isolation and interlock features function upon receipt of an initiation signal.
6. Each HPCF loop operates automatically in a minimum flow mode to protect the pump from overheating.	6. Logic and functional testing shall be performed to demonstrate operation of the minimum flow mode for each loop (including extended minimum flow operational conditions).	6. HPCF System logic functions automatically to assure that a pump minimum flow path exists and no deleterious affects are observed during extended operation in the minimum flow mode.
7. The HPCF pumps are interlocked from starting without an open suction path.	7. Logic tests shall be conducted to demonstrate that the HPCF pumps will not start without an open suction path being available.	7. An HPCF pump start signal is not generated in the absence of indication of an open suction path.
8. The HPCF System utilizes a continuously open connection from the Makeup Water (Condensate) System (MUWC) to keep the pump discharge lines filled.	8. Functional tests will be performed to demonstrate the ability of the MUWC System to keep its respective HPCF pump discharge line full while in the standby mode.	8. The MUWC System performs its keep-fill function.
9. The HPCF System full flow test mode allows periodic demonstration of HPCF capability during normal power operation.	9. Functional tests will be performed to demonstrate operation in the full flow test mode.	9. Each HPCF subsystem demonstrates full flow functional capability while approximating actual vessel injection conditions during operation in the full flow test mode.
10. The HPCF pumps have sufficient NPSH during all postulated operating conditions.	10. Actual system installation will be inspected, and appropriate measurements taken, to verify adequate pump NPSH.	10. Minimum pump NPSH available, as determined based on as-built conditions, exceeds pump required NPSH for saturated water conditions.

Table 2.4.2: High Pressure Core Flooder System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
11. HPCF mechanical equipment is built in accordance with ASME Code, Section III requirements.	11. Procurement records and actual equipment shall be inspected to verify that applicable HPCF System components have been manufactured per the relevant ASME requirements.	11. HPCF equipment has appropriate ASME, Section III, Class 1 or 2 certifications in accordance with its proper classification (Section 2.4.2).
12. Control room indications are provided for HPCF System parameters as specified in Section 2.4.2.	12. Inspections will be performed to verify presence of control room indication for the HPCF System (Section 2.4.2).	12. The instrumentation is present in the control room (Section 2.4.2).
13. The HPCF pumps have adequate head/flow characteristics.	13. Pump vendor test records and calculations will be inspected, and as-installed system flow testing conducted, to establish pump head/flow characteristics.	13. HPCF pumps, in as-installed system configuration, demonstrate head/flow characteristics consistent with design basis analyses assumptions.
14. HPCF pump suction automatically switches over from CST to the suppression pool on low CST or high suppression pool water level with override protection.	14. System logic testing using simulated input signals shall be performed to demonstrate auto switch-over of suction source and override.	14. Suction auto transfer occurs on low CST or high suppression pool water level.
15. HPCF System auto shutdown on high reactor water level and auto re-start capability.	15. Functional testing using simulated input signals shall be performed on the system logic to demonstrate HPCF systems capability to automatically shutdown on high reactor water level, and automatically re-start when low water level re-occurs.	15. HPCF auto shutdown on high reactor water level, and auto re-start on low reactor water level.

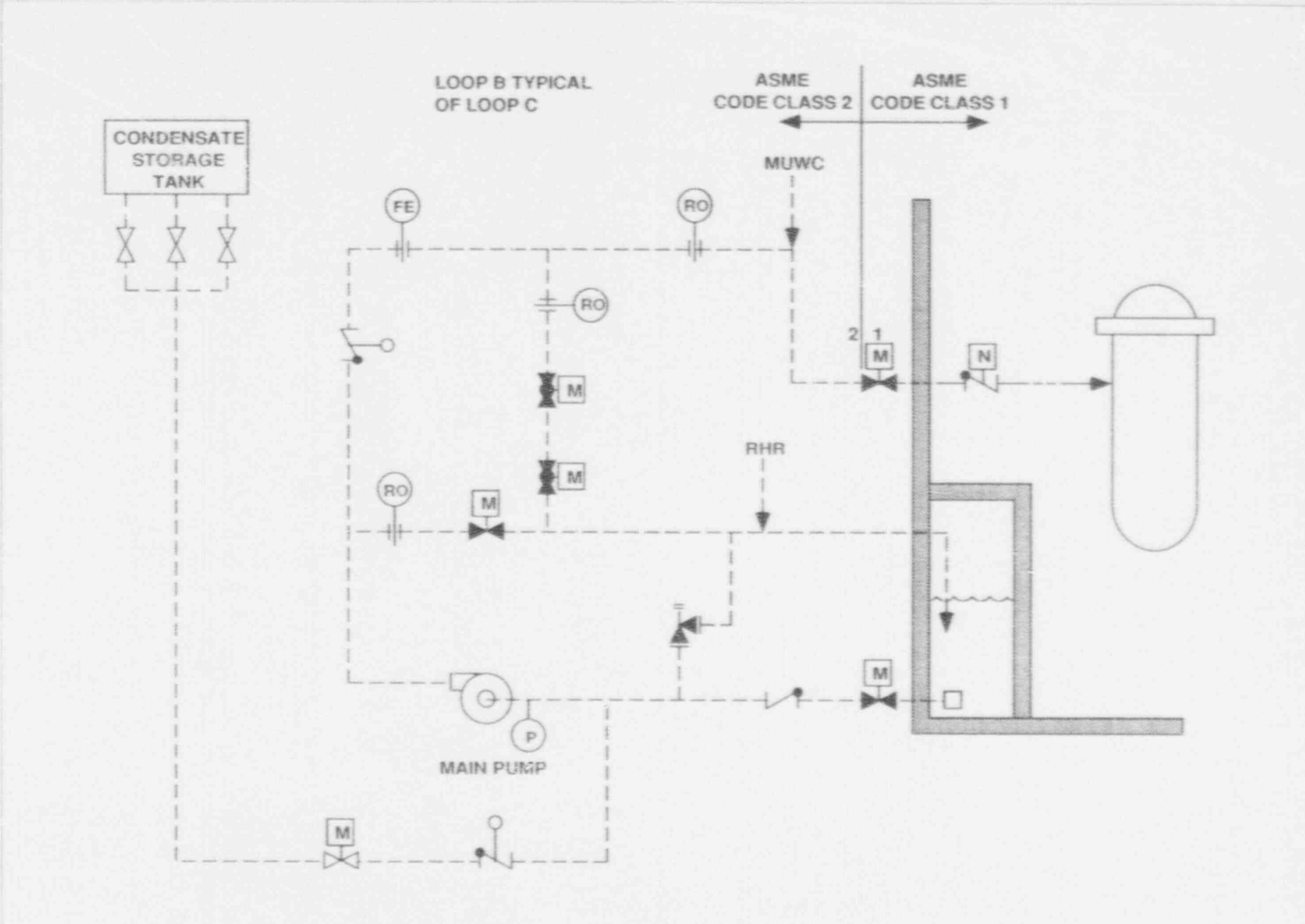


Figure 2.4.2 High Pressure Core Flooder System

2.4.3 Leak Detection and Isolation System

Design Description

The primary function of this system is to detect and monitor leakage from the reactor coolant pressure boundary (RCPB) and to initiate the appropriate safety action to isolate the leakage source and prevent further radiological releases from the RCPB. The system is designed to automatically initiate isolation of the main steamlines and other process lines that connect to the containment. Isolation results in closure of the appropriate containment inboard and outboard isolation valves. The LDS functions include containment isolation following a LOCA event, monitoring of leakages inside and outside the primary containment, monitoring of identified and un-identified leakages in the drywell, and annunciating excessive leakages in MCR.

LDS is a four divisional safety system. The instrumentation that initiates containment isolation consist of four redundant divisional channels for each monitored plant variable. The logic design is such that any two-out-of-four channel trip will result in initiation of the appropriate isolation function.

Various plant parameters are constantly monitored for indication of reactor coolant leakage such as flow, pressure, water level, temperature, radiation ... etc. All LDS safety related measurements are transmitted to the microprocessor based Safety System & Logic Control (SSLC) System for processing, setpoint comparisons, and generation of the required trip signals that initiate the isolation functions. The LDS control and isolation signals are sealed-in and will require manual logic reset to return the logic to its normal status.

The following automatic control functions are provided by LDS:

(1) Isolation of B21/MSIVs and MSL drain valves on low reactor water level (L1.5), high MSL flow in any steamline, high MSL tunnel area radiation, high ambient temperature in MSL tunnel area or in turbine building, low main condenser vacuum, or low inlet turbine pressure as shown in Figure 2.4.3a.

(2) Isolation of G31/CUW system process lines on low reactor water level (L2), high ambient MSL tunnel area temperature, high mass differential flow, high ambient temperature in equipment areas, or when C41/SLCS is activated.

(3) Initiation of T22/SGTS operation on high drywell pressure, low reactor water level (L3), or high radiation in the secondary containment.

(4) Isolation of reactor building U41/HVAC ventilation system on high drywell pressure, low reactor water level (L3), or high radiation in the secondary containment.

(5) Isolation of containment purge and vent lines of T31/AC system on high drywell pressure, low reactor water level (L3), or high radiation in the secondary containment.

(6) Isolation on high drywell pressure or low reactor water level (L1) of the P21/RCW cooling water lines to drywell coolers and RIP heat exchangers, and of the P24/HNCW cooling water lines to drywell cooling system.

(7) Isolation of E11/RHR shutdown cooling loops on high reactor pressure or low reactor water level (L3), and isolation of each RHR shutdown cooling loop on high ambient temperature in its equipment area.

(8) Isolation of E51/RCIC steamline to the turbine on high steamline flow, low steamline pressure, high turbine exhaust pressure, or high equipment area temperature.

(9) Isolation of G51/SPCU suppression pool clean-up system on high drywell pressure or low reactor water level (L3).

(10) Isolation of T49/FCS flammability control system lines on high drywell pressure or low reactor water level (L3)

(11) Isolation of the drywell sumps drain lines on high drywell pressure, low reactor water level (L3), or high radioactivity in the drained liquid.

(12) Isolation of fission products monitor drywell sampling lines on high drywell pressure or low reactor water level (L2).

(13) Initiation of C51/NMS ATIP withdrawal on high drywell pressure or low reactor water level (L3).

In addition to those functions specified above, the following parameters are continuously monitored by LDS for indication of leakages:

(1) Condensate flow from the drywell air coolers - one flow channel

(2) Drywell sump levels changes - one level sensor per sump

(3) Drywell air temperature - four thermocouple channels

(4) Valve stem leakages inside drywell - one temperature sensor per valve

(5) Differential ambient temperature in equipment areas - one set of thermocouples per equipment area (MSL tunnel, RHR, RCIC and CUW areas)

As shown in Figures 2.4.3b and d, LDS consists of instrument channels and logic units that initiates the isolation functions. Also, manual controls are provided as described beolw for isolation and logic reset, MSIV mode control and test, and for channel bypass.

LDS utilizes the essential and non-essential multiplexing systems (EMS & NEMS) as appropriate for data conversion and transmission except for the signals that control the MSIV pilot solenoids which are hard wired.

LDS is a four division system designed to provide reliable single-failure proof capability to automatically initiate the isolation functions. A single channel failure or a loss of one divisional power to a single channel will not cause inadvertent isolation. Also, LDS incorporates logic provisions to permit bypass of single division of channel at a time to facilitate maintenance and repair. The main condenser vacuum channels provided for MSIV isolation can be bypassed manually or automatically during all modes of reactor operations except when in the run mode to guard against MSIV spurious isolation.

LDS provides the following control signals to each MSIV which contains three pilot solenoids, #2 and #3 for mode control and #1 for test only as shown in Figure 2.4.3c:

(1) Two-out-of-four control signals to solenoids #2 and #3 to open the valve. MSIV closure is automatic on loss of signals to both solenoids.

(2) Two divisional control signals to test solenoid #1 to exercise valve closure during normal reactor operation. Division 1 or 3 is used to test the outboards MSIVs and division 2 or 4 will test the inboard MSIVs.

Also, LDS provides three divisional trip signals (Div 1, 2, and 3) as shown in Figure 2.4.3b for isolation of the appropriate containment isolation valves.

The LDS design incorporates the following manual control switches for isolation of the MSIVs, the containment isolation valves, and the RCIC system:

(1) Four divisional MSIV isolation switches - one per division

Simultaneous closure of all the MSIVs requires the use of two divisional switches, either divisions 1 and 4 or 2 and 3.

(2) Three PCV containment isolation switches - one per division 1, 2 and 3

Each divisional switch will isolate all its respective divisional containment isolation valves except for the MSIVs and RCIC.

(3) Two RCIC isolation switches - one per division 1 and 2

Either divisional switch will isolate the steam line to the RCIC turbine and cause turbine shutdown. Division 1 will isolate the inboard and division 2 will isolate the outboard isolation valves.

Logic reset switches (9 total) are provided on a divisional bases for manual reset of the logic, complementing the number of isolation switches that are provided as described above.

In addition to the isolation and logic reset switches, each MSIV is provided with a mode control switch (dual bank) which supplies division 1 and 2 signals for energizing its pilot solenoids #3 and #2, respectively. Also, each MSIV is provided with a test switch (dual bank) which supplies two divisional signals to its solenoid #1 for exercising valve closure to its 90% open position during reactor operation.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.4.3 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria for the Leak Detection and Isolation System.

Table 2.4.3: Leak Detection and Isolation System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. LDS is designed as a safety system to detect leakage from the RCPB by monitoring changes in plant parameters, alarm the high leakage levels in MCR, and initiate closure of the appropriate containment isolation valves.	1. Each LDS channel shall be checked for proper calibration either by reviewing certified records, by performing channel response tests and/or by cross channel comparison. To check channel integrity and operabitity, a simulated signal input shall be used to verify initiation of the appropriate trip signal at the specified setpoints for alarming and/or isolation.	1. Proper channel calibration and response is verified when the records and/or the test results are considered acceptable. Also, channel integrity and operability is verified when the trip signal that initiates an alarm and/or isolation occurred at the setpoint.
2. Four redundant safety divisional channels are provided to monitor each plant variable. The logic design is such that any two out of four channel trip will initiate an isolation.	2. Each LDS logic isolation function shall be tested using various simulated signal inputs to verify that isolation occurs only when any two or more out of the four channels indicate trip.	2. Acceptance is based on satisfying the required two out of four criteria for initiating an isolation function.
3. The LDS logic design permits bypass of a single division of sensors at any one time to permit test and maintenance during normal reactor operation without causing outage.	3. While in channel bypass, each LDS logic isolation function shall be tested using various simulated inputs to verify that isolation occurs only when any two or more out of three channels indicate trip.	3. Acceptance is based on satisfying the required two out of three criteria for initiating an isolation function while in the bypass mode.
4. The LDS design provides each MSIV with a dual-bank mode control switch to open and close the valve, and with a dual-bank test switch to exercise valve closure during reactor operation.	4. Actuation of the MSIV mode switch shall cause the valve to open. The mode switch shall provide 2 control signal, Div 1 to pilot solenoid #3 and Div 2 to pilot solenoid #2. Actuation of the test switch shall cause the valve to partially close to its 90% open position and then return to normal. The test switch shall provide Div 1 and 3 for the outboards and Div 2 and 4 for the inboard MSIVs.	4. Acceptance is based on verifying valve operation under the specified conditions. Div 1 and 2 mode switch control signals when applied to MSIV pilot solenoids #3 and #2, respectively, cause the MSIV to fully open. Either divisional control signals from the test switch when applied to MSIV pilot solenoid #1 cause partial closure.

Table 2.4.3: Leak Detection and Isolation System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. The LDS design provides control switches to isolate separately the MSIVs, RCIC and the PCV as follows: a. Four MISV switches, one/division 1 to 4 b. Two RCIC switches, one/division 1 and 2 c. Three PCV switches, one/division 1 to 3	5. a. Simultaneous closure of the MSIVs shall occur when two MSIV switches are actuated, Div 1 and 4 or Div 2 and 3. b. RCIC system shall be isolated by either Div 1 or 2 switch. (Div 1 for inboard and Div 2 for outboard valves.) c. Each PCV divisional switch shall isolate its respective divisional containment isolation valves.	5. Confirmation that each specified manual isolation function was properly implemented. Also, closure of each valve is confirmed by its indicating position status light , RED for close position and GREEN for open position.
6. The main condenser vacuum logic channels are bypassed during startup and shutdown to guard against spurious isolation.	6. Verify that each main condenser vacuum channel can be manually or automatically bypassed by the logic without causing MSIV trip under simulated conditions.	6. Verification that each main condenser vacuum logic channel can be bypassed as indicated by the logic.
7. The LDS design provides divisional logic reset switches that are used for initial set of the logic to de-energize to trip and for logic reset after the trip conditions have cleared.	7. The divisional logic isolation channel of the MSIVs, RCIC, and the PCV shall be initially set. Four switches (1/Div) are provided for MSIV logic reset, two switches (1/Div) for RCIC logic reset, and three switches (1 for Div 1, 2 and 3) for PCV logic reset.	7. Confirmation that the divisional logic for the specified functions are normally set.
8. LDS monitors identified and un-identified leakages in the drywell and alarms in MCR excessive leakages.	8. Verify that the instrumented channels that monitor sump level changes, drywell coolers condensate flow, and leakages from valve stems are operable and the alarm setpoints are correctly set.	8. Confirmation that each instrumented channel is operable and that alarm setpoints are verified.

2.4.3

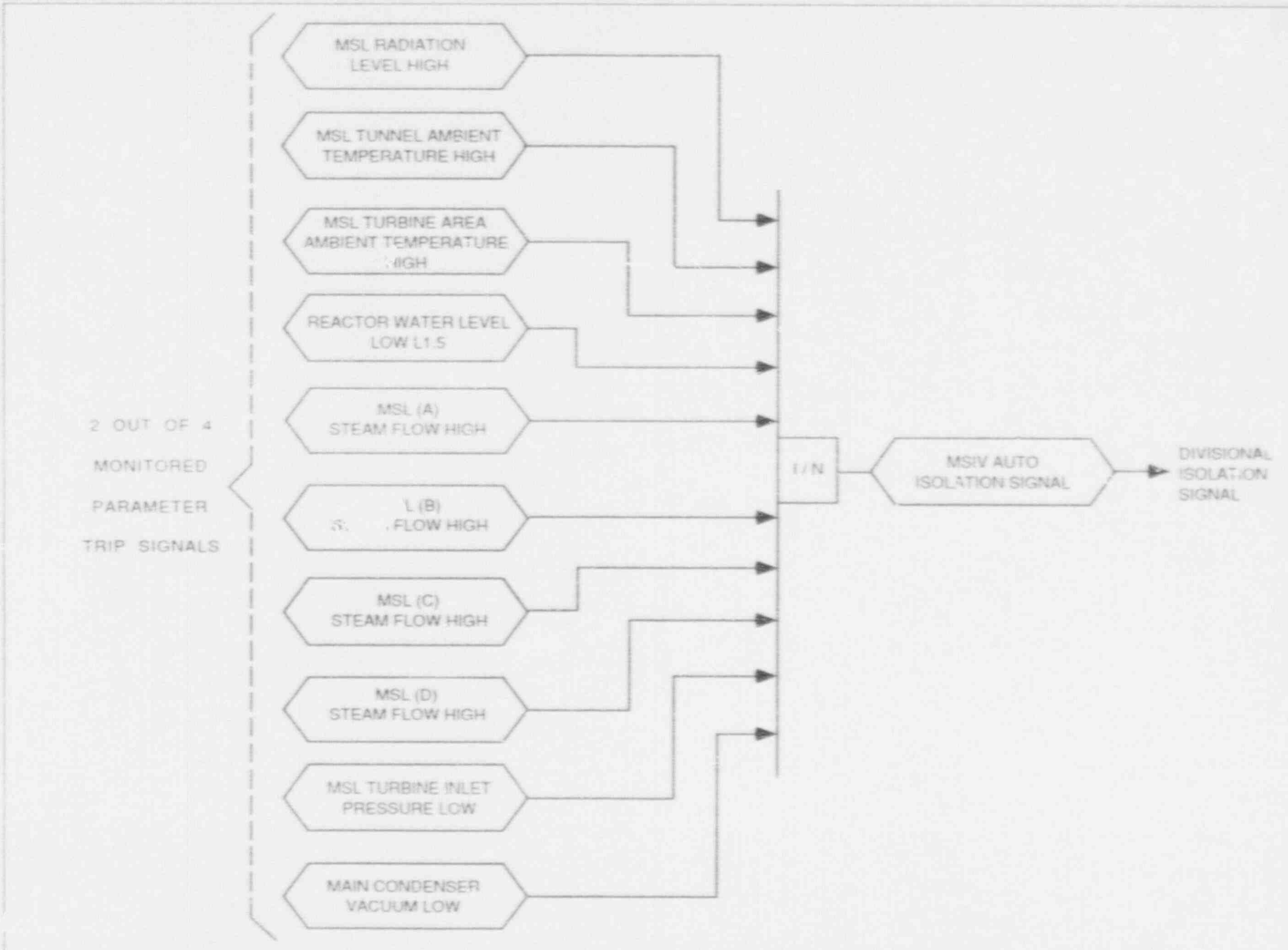


Figure 2.4.3a MSIV Trip Signal (Typical for Division I - IV)

6/1/92

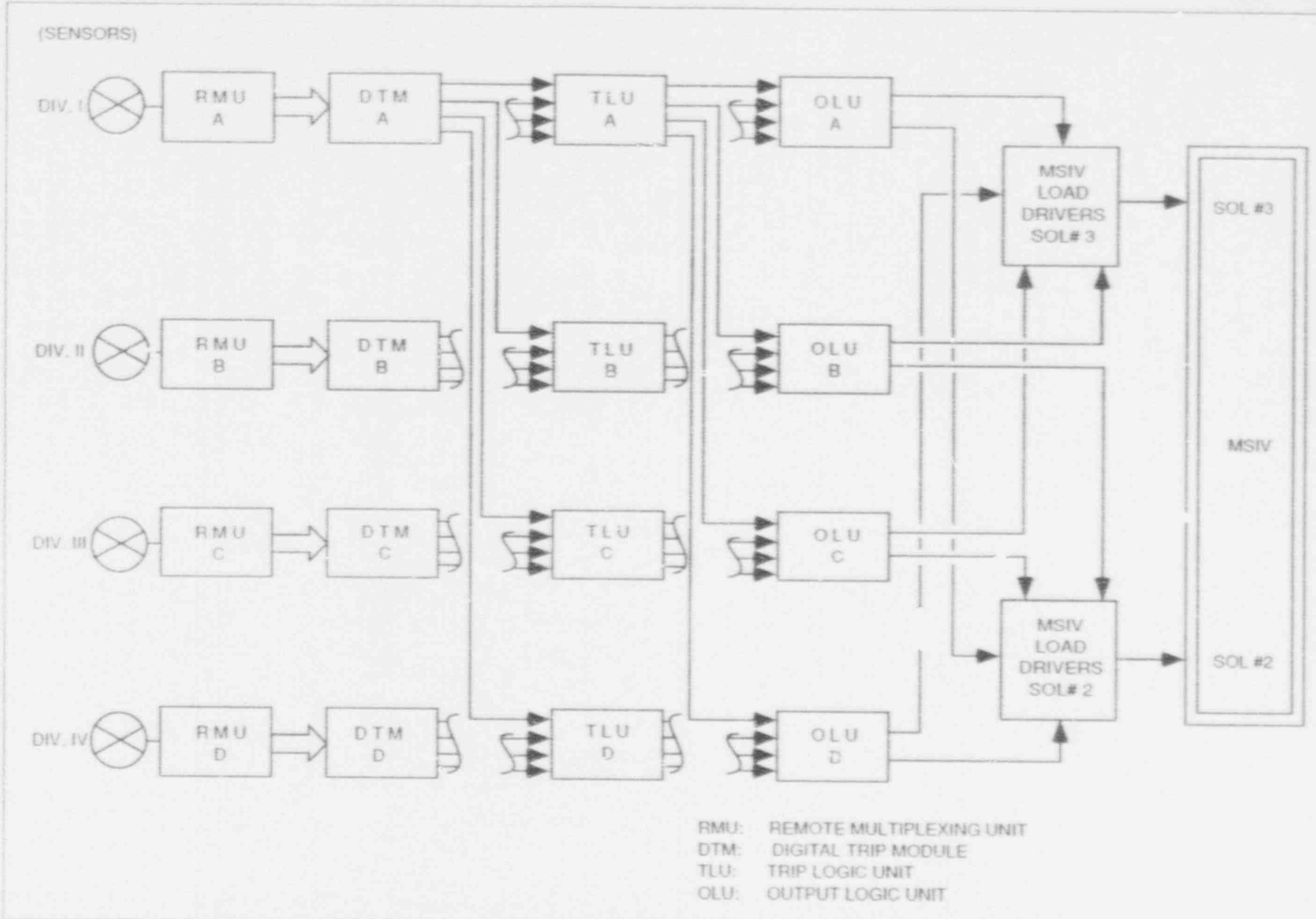


Figure 2.4.3b LDS/MSIV Channel Configuration

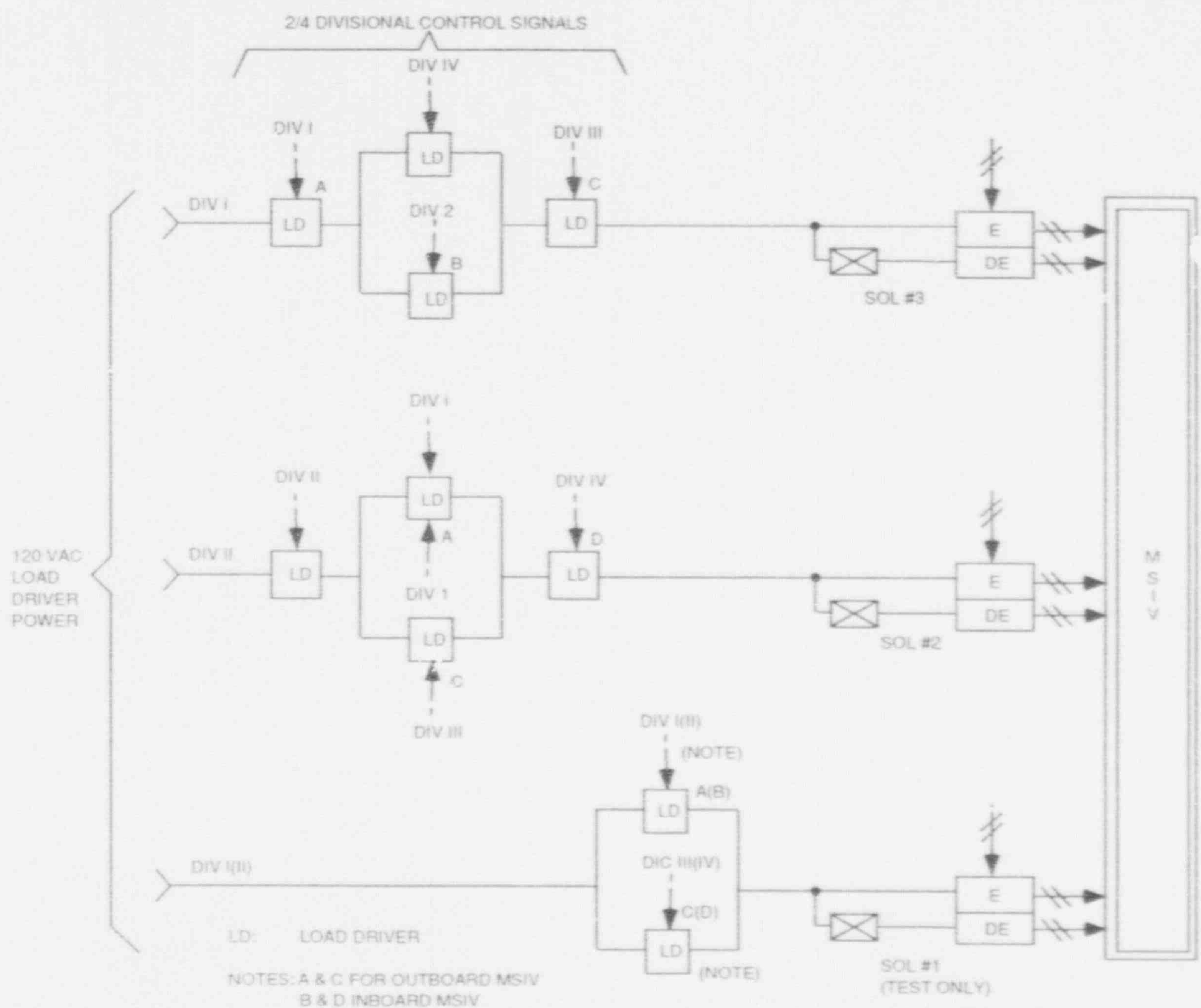


Figure 2.4.3c MSIV Load Driver Arrangement

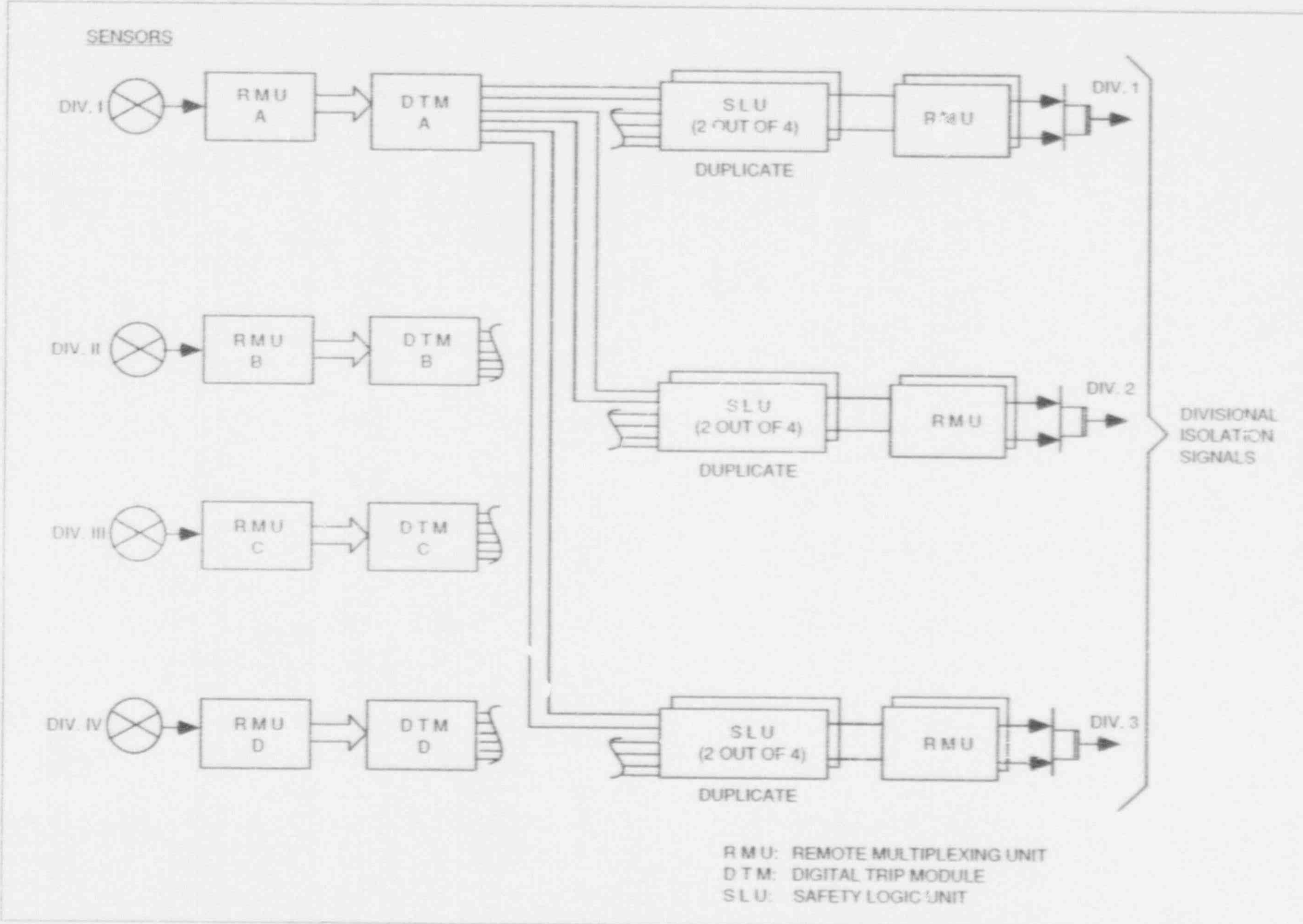


Figure 2.4.3d LDS Logic Configuration (Except for MSIV Logic)

2.4.4 Reactor Core Isolation Cooling System

Design Description

The Reactor Core Isolation Cooling (RCIC) System, in conjunction with other systems, supplies makeup water to the reactor pressure vessel to assure that sufficient water inventory is maintained to permit adequate core cooling to take place during the following events:

(1) Loss-of-coolant accident (LOCA).

(2) Vessel isolated and maintained at hot standby.

(3) Vessel isolated and accompanied by loss of feedwater flow.

(4) Complete plant shutdown with loss of normal feedwater system before the reactor is depressurized to a level where the shutdown cooling mode of the RHR System can be placed in service.

(5) Loss of all AC power.

The RCIC System consists of a 100% capacity steam-driven turbine which drives a 100% capacity pump assembly and the pump accessories. The system also includes piping, valves, and instrumentation necessary to provide several flow paths for system operation. The RCIC steam supply branches off from main steamline "B" (leaving the RPV) and goes to the RCIC turbine with drainage provision to the main condenser. The turbine exhausts to the suppression pool with vacuum breaking protection. The primary source of RCIC suction supply is from the Condensate Storage Tank (CST). The suppression pool water is the secondary source of RCIC supply. Automatic switchover of makeup water source from the CST to the suppression pool (with override provision) is integrated in the system logic. CST and suppression pool suction valves are interlocked, and check valves are provided to safeguard accidental drainage of CST water to the suppression pool. RCIC pump discharge lines include the main discharge to the feedwater line, a test return line to the suppression pool, a pump minimum flow bypass line to the suppression pool, and a cooling water supply line to auxiliary equipment. The piping configuration and instrumentation are shown in Figure 2.4.4.

The RCIC System is a part of the ECCS network and is designed to safety-related standards. It is powered from Class 1E DC sources (except the inboard steam supply isolation valve, which has Class 1E AC), and is designed to perform its function deprived of all AC sources. Although RCIC System design is safety related, it also performs some non-safety-related functions. The safety-related functions include emergency core cooling, in conjunction with the High Pressure Core Flooder (HPCF) System, Automatic Depressurization System

(ADS) and the Residual Heat Removal (RHR) System. As part of this network, the RCIC System can provide reactor makeup in the period while the reactor is still at high pressure after a small break has occurred. The non-safety-related functions include providing makeup water to the reactor pressure vessel (1) during transient events accompanied by loss of feedwater, and (2) during a complete loss of all AC power (Station Blackout).

During normal operation, the RCIC System is in its standby condition with the motor-operated valves in their normally open or normally closed position (Figure 2.4.4). In this mode, the pump discharge line is kept filled with water supplied by the system head of the Condensate Makeup System to prevent waterhammer in the discharge piping system when the RCIC System is initiated. Full flow functional testing may be performed with the RCIC pump taking suction from and returning flow to the suppression pool. Should an initiation signal occur during test mode, the system configuration would automatically realign to the vessel injection mode.

During transient and LOCA events, RCIC System is automatically initiated upon receipt of low reactor water level or high drywell pressure signal. The steam turbine-driven pump delivers water from the CST or from the suppression pool to the reactor vessel via the feedwater line "B" and distributes it through the feedwater sparger to promote mixing with hot water or steam within the reactor vessel. The RCIC turbine is driven by the portion of the decay heat steam from the reactor vessel, and exhausts through a discharge sparger below the suppression pool water level. The turbine exhaust line penetrates the containment a· · location about 1 meter above the suppression pool maximum water level. Two vacuum breakers in series are connected to the exhaust line (above the suppression pool water level) in the wetwell air space. A check valve and a remote manually operated motorized valve installed in series outside the containment provides containment isolation function for the turbine exhaust line.

When high reactor water level in the reactor vessel has been established, the vessel injection valve and the steam supply admission valve to the turbine will close, causing the turbine to shut down. When the low reactor water level initiation signal re-occurs, the RCIC System will automatically restart to provide the core cooling function.

The RCIC turbine is automatically tripped (turbine trip and throttle valve isolated) upon receipt of any signal indicating turbine overspeed, low pump suction pressure, high turbine exhaust pressure, or an auto-isolation signal from the Leak Detection System (LDS). Once tripped, the spring closing mechanism latches and must be manually reset if the turbine needs to be re-started. This very same isolation signal (LDS) also isolates the RCIC steam supply isolation valves to provide primary containment isolation. The LDS isolation signals are as follow:

(1) A high pressure drop across a flow device in the steam supply line equivalent to 300% of the steady-state steam flow.

(2) A high RCIC area temperature.

(3) A low reactor pressure (low steamline pressure).

(4) A high pressure between the RCIC turbine exhaust rupture diaphrams.

The RCIC System can also be manually initiated and shut down from the main control room as long as permissive interlocks are present.

In the event that all AC power sources are not available (Station Blackout), the RCIC System is designed to perform its core cooling function for at least 8 hours. Station batteries and CST water inventory are sized to support the 8-hour RCIC operation. The RCIC room is designed such that room temperature does not reach the equipment maximum environmental limit for at least 8 hours without room cooling. The RCIC steam supply isolation valves are normally open motor-operated valves. These valves fail as-is (open) on loss of AC power, thereby providing steam supply flowpath to the turbine. During this event, the reactor pressure is controlled and maintained at the main steam safety/relief valve (SRV) set pressure to assure an 8-hour steam supply to the RCIC turbine.

The RCIC System is designed to Seismic Category I requirements and is housed in a Seismic Category I reactor building structure to provide protection from tornadoes, floods, and other natural phenomena.

The RCIC System also includes provision for primary containment and RCPB pressure isolation. The RCIC piping system and valves are Seismic Category I Quality Group B except for the steam supply piping, which is Seismic Category I, Quality Group A up to and including the outermost primary containment isolation valve. The inboard and outboard isolation valves are powered from independent Class 1E sources. The steam supply piping up to and including the turbine has a design pressure of 87.9 kg/cm^2g and a design temperature of 302°C, while the turbine exhaust piping is designed to 10 kg/cm^2g and 184°C. The RCIC pump discharge piping up to the injection valve is designed to 120 kg/cm^2g and 77°C. The injection valve itself is rated at 120 kg/cm^2g and 302°C. Beyond the injection valve, the discharge piping portion that connects to the feedwater line is rated at 87.9 kg/cm^2g and 302°C. The pump suction piping is rated at 21 kg/cm^2g and 77°C. Protection of the low pressure suction piping from potential high reactor pressure is accomplished by three valves in series (testable check valve, injection valve and pump discharge check valve) at the pump discharge line.

The RCIC turbine which drives the pump is a safety-related component, although not covered by the ASME Code. The gland seal is not safety-related, but it is not essential for RCIC operation. The turbine and its accessories are seismically designed and analyzed to withstand a design basis earthquake (DBE). The turbine is designed to operate at both high and low pressure conditions. The minimum steam inlet pressures at high pressure condition is 82.8 kg/ cm^2abs, and 10.5 kg/cm^2abs for the low pressure condition.

The RCIC pump is designed to Seismic Category I, Quality Group B. The pump is a constant flow centrifugal type capable of providing an injection flow into the reactor vessel of at least 182 m^3/hr against a differential pressure of 82.8 kg/cm^2 (drywell to RPV) within 30 seconds following receipt of initiation signals. The suction piping configuration is designed such that adequate NPSH is always available on all RCIC operating modes. Pump developed head is about 900 meters at 83.8 kg/cm^2abs and 186 meters at 11.6 kg/cm^2abs reactor pressure.

The RCIC System includes control room indications and alarms to allow for the monitoring and control during the design basis operational conditions, i.e., system flows, temperatures, pressures, valve open/close and pump on/off conditions, and bypassed, override or inoperative status conditions.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.4.4 provides a definition of the inspections, tests and/or analyses together with associated acceptance criteria which will be undertaken for the RCIC System.

Table 2.4.4: Reactor Core Isolation Cooling System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the RCIC System is shown in Figure 2.4.4.	1. Inspection of the as-built RCIC configuration shall be performed.	1. Verification of the as-built system is in conformance with the as-designed configuration (Figure 2.4.4).
2. The RCIC System automatically re-aligns to vessel injection mode if a LOCA signal occurs while the system is in test mode.	2. Using simulated LOCA signal, functional testing of the system logic shall be performed to demonstrate the system's capability to revert to the vessel injection mode while in test mode.	2. RCIC System automatically re-aligns to vessel injection mode upon receipt of LOCA signal.
3. RCIC pump is capable of delivering a flow rate of $\geq$182 m^3/hr against 82.8 kg/cm^2d.	3. Vendor to conduct shop tests relating to pump performance.	3. Verification of certified documentation demonstrating that the pump will meet $\geq$182 m^3/hr against 82.8 kg/cm^2d.
4. Steam supply isolation valves are capable of closure against the maximum design basis differential pressure.	4. Vendor to conduct shop tests relating to valve operation during design basis events.	4. Valve closure occurs against design basis differential pressure.
5. RCIC pump suction automatically switches over from CST to the suppression pool on low CST or high suppression pool water level with override provision.	5. System logic testing shall be performed to demonstrate auto switchover of suction source and override.	5. Suction auto transfer occurs on low CST or high suppression pool water level.
6. RCIC steam supply isolation valves fail as-is (open) on loss of AC power.	6. Field testing shall be performed to demonstrate that the steam supply isolation valves (normally open motorized valves) will stay in the open position when AC power is lost.	6. Valves remain open upon removal of AC power.
7. RCIC steam supply isolation valves isolate upon receipt of auto-isolation signals from Leak Detection System in $\leq$ 30 seconds.	7. Functional testing shall be performed on the system logic by simulating the auto-isolation signal from LDS.	7. Valves isolate within $\leq$30 seconds from receipt of auto isolation signals.
8. RCIC System auto shutdown on high reactor water level and auto re-start capability.	8. Functional testing shall be performed on the system logic to demonstrate RCIC System's capability to automatically shutdown on high reactor water level, and automatically restart when low water level re-occurs.	8. RCIC auto shutdown on high reactor water level, and auto re-start on low reactor water level.

Table 2.4.4: Reactor Core Isolation Cooling System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9. RCIC mechanical equipment (except the turbine) is built in accordance with ASME Code Section III requirem...	9. Procurement records and actual equipment shall be inspected to verify that applicable RCIC System components have been designed, manufactured and installed per relevant ASME Code.	9. Certified documentation demonstrates compliance with the appropriate ASME Code.
10. Provision for control room alarms, and indications vital for RCIC System operation.	10. Inspection will be performed to verify presence of control room alarms and indications.	10. The control room alarms and indications specified in Section 2.4.4.

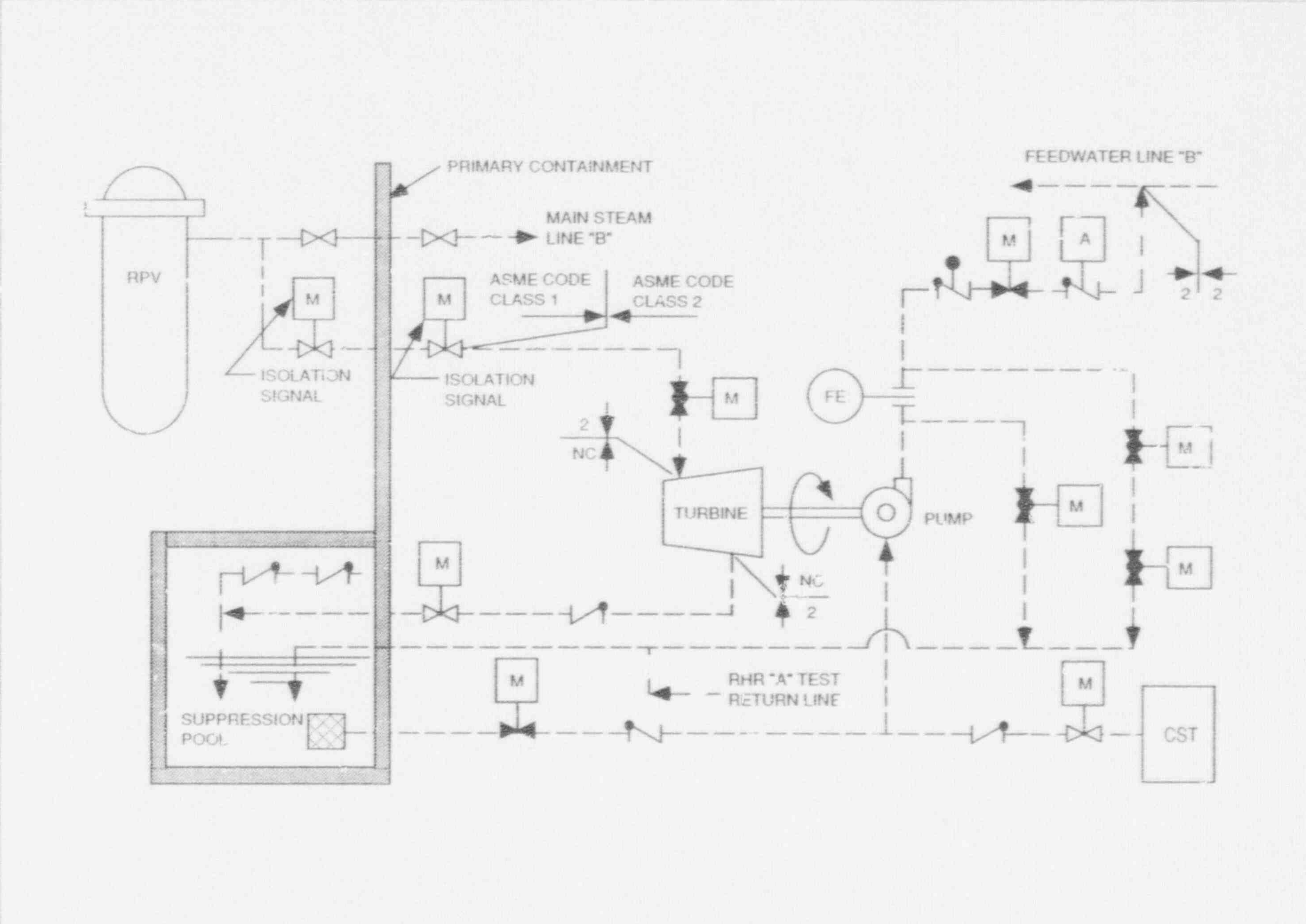


Figure 2.4.4 Reactor Core Isolation Cooling (RCIC) System P&ID

2.5 Reactor Servicing Equipment

2.5.1 Fuel Servicing Equipment

Design Description

The fuel servicing equipment is that equipment required for normal planned reactor refueling outage. This equipment will be used with other general plant equipment that is not covered here. Also listed with this equipment is the Refueling Platform and this is covered in section 2.5.5.

Fuel servicing equipment has an "Non-Essential Classification", "Safety Class" of other, "Quality Group" of Electrical Codes and a 'Seismic Category' of none. The only exception to this is the New Fuel Inspection Stand which is "Passive Essential" and "Safety" class 2.

Fuel Prep Machine

The spent fuel storage pool has two fuel prep machines mounted to the pool walls. These machines are used for the stripping reusable channels from spent fuel and for channeling of the new fuel. These machines also provide an under water inspection capability of the fuel. The fuel is mounted to the carriage which has an upper travel stop.

New Fuel Inspection Stand

This fixture is a stand that holds two fuel assemblies for receiving inspection. There is a movable work platform surrounding the stand which allows the technicians to perform the inspection. The stand is firmly attached the wall on the refueling floor.

Channel Bolt Wrench

This is a long socket wrench that fastens and unfastens the cap screw holding the channel to the fuel assemble. The wrench also captures the screw.

Channel Handling Tool

This is a manually operated channel grapple that uses the area boom on the jib crane to support the weight.

Vacuum Sipper

This is a fuel isolation container for the monitoring of suspected cladding failures. Fission product gas leakage is sensed by the Beta detector and monitoring console.

General Purpose Grapple

Generally used for fuel handling and support by the area jib crane. Used primarily in conjunction with the fuel prep machine.

Channel Handling Boom

This is a jib crane located in the area of the fuel prep machines. It is used to conveniently move items between the fuel prep machine and the storage racks.

Inspections, Tests, Analyses and Acceptance Criteria

No entries for this system.

2.5.2 Miscellaneous Servicing Equipment

Design Description

This equipment is generally used independently of other servicing equipment. Equipment requirements are that they operate in a environment up to a depth of 33 meters. Other requirements are that the equipment can be quickly decontaminated and can be stored with a minimum of manpower.

Under Water Lights

Three types of lights are used; A general area, a local area and a drop type light.

Viewing Aids

Three types of viewing aids are used; The floating type is the simplest, the under water viewing tube is a 15-60 power telescope and the last is a under water remotely controlled television camera with an internal light source.

Under Water Vacuum Cleaner

The vacuum cleaner rests on the pool floor and is completely serviceable there. The power and control comes from the refueling floor by cables and the cleaner has its own accessories.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.5.2 provides definition of the inspection, test and/or analyses together with associated acceptance criteria which will be undertaken for the Servicing Equipment.

Table 2.5.2: Miscellaneous Servicing Equipment

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspection, Test, Analysis	Acceptance Criteria
1. Environment 33 meters of water.	2. Install vacuum cleaner in 33 meters of water and give operation test.	1 Visually evaluate the cleaner operations.
2 Environment 33 meters of water.	2. Install television camera in 33 meters of water and give operation test.	1 Visually evaluate the camera operations.

2.4.4

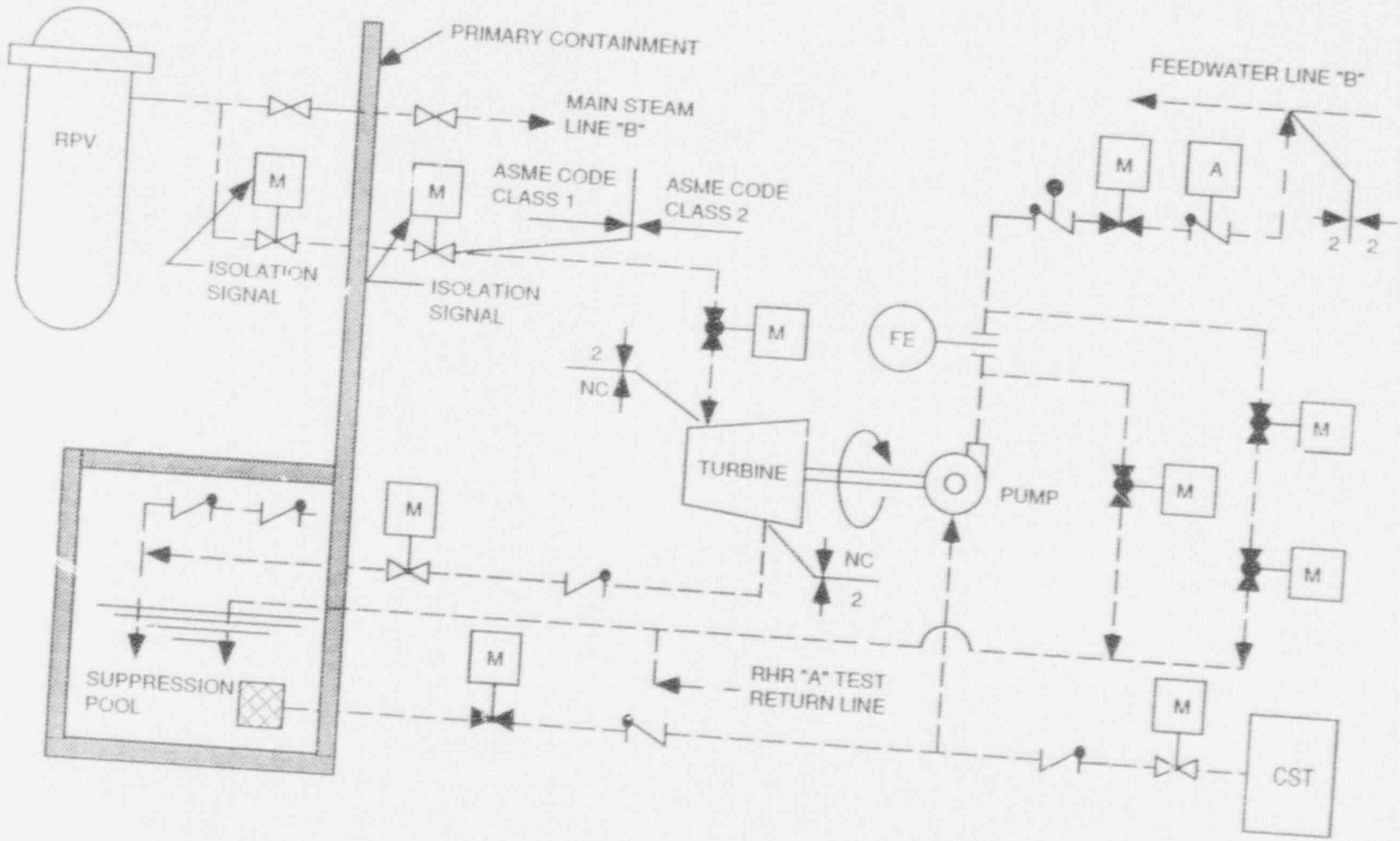


Figure 2.4.4 Reactor C

Dryer and Separator Strongback

The strongback is used to move the steam dryer or shroud head with steam separator between the vessel and storage. The strongback has pneumatically operated pins to engage the steam dryer or shroud head. The strongback is designed in accordance with the AISC and has a Safety Factor of 10 or better with respect to the ultimate strength of the material. The strongback is proof-tested at 125% of rated load and all welds are magnetic particle inspected after load test.

Head Strongback/Carousel

The strongback is a combination of strongback, circular monorail and circular storage tray. The strongback services many functions with respect to the vessel head. The construction of the strongback is in accordance with the applicable AISC requirements. The strongback is designed to provide a 15% impact allowance and a Safety Factor of 10 or better to the ultimate strength of the material. The strongback is also designed to meet the applicable Crane Manufacturers Association of America, Specification and be tested in accordance with applicable ANSI requirements. All welding will be in accordance with The ASME Boiler and Pressure Vessel Code, Section IX, Welder Qualification and proof load testing will be preformed with magnetic-particle inspection before coating.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.5.3 provides definition of the inspection, test, and/or analysis together with associated acceptance criteria which will be undertaken for the RPV Servicing Equipment.

Table 2.5.3: RPV Servicing Equipment

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspection, Test, Analysis	Acceptance Criteria
1. All tools have 60-year life.	1. Examine the design data.	1. Design data shows compliance.
2. Steam line plug safety factor of 5.	2. Examine analysis.	2. Analysis shows safety factor of 5.
3. Steam line plug is constructed to ACM code.	3. Examine certification data report.	3. Certification data report shows compliance with ACM code.
4. Meet or exceed the requirements of the AISC using the floor response spectrum method of seismic analysis for pedestal.	4. Examine certification analysis report.	4. Certification data shows compliance with AISC.
5. Pedestal approved coating.	5. Examine certification data report.	5. Data report shows compliance.
6. Rack to store 8 studs.	6. Visual inspection of rack capacity.	6. Visual inspection provides verification.
7. Rack safety factor of 5.	7. Examine analysis.	7. Analysis data provides verification.
8. Rack is constructed to ACM code.	8. Examine certification data report.	8. Certification data report shows compliance with ACM code.
9. D/S strongback constructed to ASIC code.	9. Examine certification data report.	9. Certification data report shows compliance with AISC code.
10. D/S strongback safety factor of 10.	10. Examine analysis.	10. Analysis data shows safety factor of 10.
11. D/S strongback proof-tested at 125% of rated load.	11. Examine certification data report.	11. Certification data shows 125% of rated load compliance.
12. D/S strongback welds are magnetic particle inspected.	12. Examine certification test results.	12. Certification data shows results of tests.
13. Head strongback construction in compliance with AISC and ACM.	13. Examine certification data report.	13. Certification data reports show compliance with AISC and ACM code.
14. Head strongback designed for 15% impact and safety factor of 10 or better.	14. Examine analysis.	14. Analysis data shows safety factor of 10 and 15% impact allowance.
15. Head strongback designed to meet applicable crane manufacturers' association requirements.	15. Examine Spec 70 and construction data report.	15. Data report shows compliance with applicable requirements.

Table 2.5.3: RPV Servicing Equipment (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspection, Test, Analysis	Acceptance Criteria
16. Head strongback testing in accordance with applicable ANSI requirements.	16. Examine test results and compare with ANSI B30.16.	16. Test results verify compliance with applicable ANSI requirements.
17. All welding in accordance with ASME Boiler and Pressure Vessel code, Section IX, welder qualification and magnetic particle inspection.	17. Examine certification data report.	17. Certification data report shows compliance and verification of ASME, BPV code Section IX, welder qualification and magnetic particle inspection.

2.5.4 RPV Internal Servicing Equipment

Design Description

The instrument strongback is used to handle LPRM, and SRNM Dry Tube from the floor to the reactor well. The auxiliary crane of the building crane shall be used to lift and rotate the strongback from horizontal position to vertical position. Then this strongback is moved towards the reactor well, lowered into the RPV. Upper portion of the strongback remains above water level so as the workers on the refueling platform can perform the operation. The Instrument Handling Tool is connected to the wire terminal of the auxiliary hoist of the refueling platform receives LPRM or Dry Tube from the strongback.

Instrument Strongback

The instrument strongback is used to support in-core dry tubes while being assembled into the open reactor vessel.

Instrument Handling Tool

The instrument handling tool is used to grip the dry tube assembly for removal from the reactor vessel.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.5.4 provides definition of the inspections, tests, and/or analyses together with associated criteria which will be undertaken for the Internal Servicing Equipment.

Table 2.5.4: RPV Internal Servicing Equipment

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspection, Test, Analysis	Acceptance Criteria
1. Strongback to be used over reactor well.	1. Examine analysis data.	1. Analysis data provides verification of safety factor of at least 10.
2. Handling tool used over reactor well.	2. Examine analysis data.	2. Analysis data provides verification of safety factor of at least 10.

2.5.5 Refueling Equipment

The Reactor Building is supplied with a refueling platform for fuel movement and servicing plus an auxiliary platform for servicing operations from the vessel flange level.

Design Description—Refueling Platform

The refueling platform is a gantry crane, which spans the reactor vessel and the storage pools on bedded tracts in the refueling floor. A telescoping mast and grapple suspended from a trolley system is used to lift and orient fuel bundles for placement in the core and/or storage racks. Control of the platform is from an operator station on the refueling floor.

A position indicating system and travel limit computer is provided to locate the grapple over the vessel core and prevent collision with pool obstacles. Two auxiliary hoists, one main and one auxiliary monorail trolley-mounted, are provided for in-core servicing.The grapple position provides sufficient water shielding over the active fuel during transit. The mast grapple has a redundant load path so that no single component failure will result in a fuel bundle drop. Interlocks on the platform: (1) prevent hoisting a fuel bundle over the vessel with a control rod removed; (2) prevent collision with fuel pool walls or other structures; (3) limit travel of the fuel grapple; (4) interlock grapple hook engagement with hoist load and hoist up power; and (5) ensure correct sequencing of the transfer operation in the automatic or manual mode.

Design Description—Auxiliary Platform

The auxiliary platform provides a reactor flange level working surface for in-vessel inspection and reactor internals servicing, and permits servicing access for the full vessel diameter. No hoisting equipment is provided with this platform, as this function can be performed from the refueling platform. The platform operates on tracks at the reactor vessel flange level and is lowered into position by the Reactor Building crane using the dryer/separator strongback. The platform power is supplied by a cable from the refueling floor elevation.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.5.5 provides definition of the inspection, test, and/or analyses together with associated acceptance criteria which will be undertaken for the refueling platform. No entries are proposed for the auxiliary platform.

Table 2.5.5: Refueling Platform

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The refueling platform has two auxiliary hoists having the capacity of 500 kg each.	1. Perform load tests on both auxiliary hoists.	1. Both auxiliary hoists shall be load tested and hold 125% of rated load.
2. The platform is provided with controls and interlocks which: a. Maintain water shielding over fuel when grappled on mast. b. Allow no fuel movement over vessel when control rod is removed. c. Provide fuel grapple travel limit. d. Prevent collision with fuel pool walls and other structures. e. Interlock grapple hook engagement with hoist load and hoist up power. f. Insure automatic sequencing control for transfer operation.	2. Review of as-installed equipment and field tests will be conducted after the platform has been installed.	2. Using normal installed controls and power, the platform meets required operating characteristics.

2.5.6 Fuel Storage Facility

Storage racks are required for the temporary and long term storage of fuel and associated equipment. Storage may be either wet or dry, depending upon the item being stored.

Design Description—Fuel Storage Racks

Racks provide storage for spent fuel in the Spent Fuel Storage Pool in the Reactor Building. The racks are top loading, with fuel bail extended above the rack, and shall have a minimum capacity of 270% of the reactor core. The rack design precludes the possibility of criticality under normal or abnormal conditions and maintains a subcriticality of at least 5% Δk. The rack arrangement and design prevents accidental insertion of fuel between adjacent racks and provides adequate water flow to prevent the water from exceeding 212°F. The racks are structurally able to maintain a Safety Class 2 and Seismic Category I. The racks are an Essential component performing a passive safety function.

Design Description—New Fuel Storage Rack

The new fuel and spent fuel storage racks are the same type rack in design, construction and height. The new fuel storage racks are located in a vault. The vault is a pit in the refueling floor that is fitted with a special cover which is in place when ever fuel is not being processed. The depth of the pit is such that, when fuel is racked, the bail is below the cover's plane. The pit is constructed the same as the spent fuel pool except that it contains a drain and is maintained dry. The new fuel storage racks store approximately 40% of one full core fuel load.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.5.6 provides a definition of the inspection, tests, and/or analyses and associated acceptance criteria which will be undertaken for the fuel storage racks.

Table 2.5.6: Fuel Storage Racks

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. A full rack is subcritical by at least 5% Δk, which includes uncertainty value and associated probability and confidence level.	1. Design documentation and records will be reviewed to confirm that required criticality margin has been provided. As-installed equipment will be compared to design documentation; reconciliation analyses will be performed if necessary.	1. The calculated k_{eff}, including biases and uncertainties, will not exceed 0.95 under normal and abnormal conditions.
2. The cooling water in the spent fuel storage pool shall be under 212°F when all storage positions are full.	2. Documentation for the as-installed racks will be reviewed to confirm that adequate cooling will occur.	2. The combination of storage racks and support structure provides adequate flow to prevent water from exceeding 212°F.
3. The structure, its appurtenances and its supports shall satisfy the ASME Class, Seismic Category and Quality Group requirements commensurate with its classification.	3. Inspections will be conducted of ASME Code required documents and the code stamp on the components.	3. Existence of ASME Code required documents and the Code stamps on the components confirms that the structure and components have been designed, analyzed, fabricated and examined in accordance with the applicable requirements.

2.5.7 Under-Vessel Servicing Equipmei.'

Design Description

The functions of the under-reactor vessel servicing equipment is to: (1) remove and install control rod drives; (2) install and remove the neutron detectors; and (3) remove and install RIP Motors. The equipment handling platform and the CRD handling equipment are powered pneumatically. This equipment is classified as Non-essential with a safety class of "Other", has no Seismic requirements and a general Industrial code quality grouping. These characteristics are valid except where noted otherwise.

Under-Vessel Platform

This is the working surface for equipment and personnel. The platform is polar and capable of rotating 360 degrees and is designed in accordance with the applicable requirements of OSHA (Vol 37, No.202, Part 1910N), AISC, ANSI-C-1, National Electric Code.

Spring Reel

The Spring Reel is used to pull guide tube seals and detectors during incore servicing.

Water Seal Cap

The Water Seal Cap is used to prevent leakage of the primary coolant during detector replacement.

Incore Flange Seal Test Plug

The Incore Flange Seal Test Plug is used to determine the pressure integrity of the incore flange O-ring seal.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.5.7 provides definition of the inspections, tests and/or analyses together with associated acceptance criteria which will be undertaken for the Under-vessel Servicing Equipment.

Table 2.5.7: Under Vessel Servicing Equipment

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspection, Test, Analysis	Acceptance Criteria
1. Platform designed in accordance with OSHA (Vol. 37, No. 202, Part 141ON).	1. Examine design data, OSHA regulation, and visual inspect platform.	1. Visual inspection and design data show compliance with OSHA.
2. Platform construction in accordance with AISC.	2. Examine design data, AISC specifications, and visual inspect platform.	2. Visual inspection and design data show compliance with AISC.
3. Same for ANSI-C-I.		
4. Same for National Electric Code.		

2.5.8 CRD Maintenance Facility

Design Description

The CRD maintenance facility is designed and equipped to accommodate the performance of fine motion control rod drive (FMCRD) maintenance related activities, including decontamination of the FMCRD components, performance of acceptance tests, and drive storage. The facility uses manual and/or remote operation to reduce radiation exposure to plant personnel and to reduce contamination of surrounding equipment during operation.

The CRD maintenance facility is housed in secondary containment near the lower drywell equipment the layout of the facility is designed to increase the efficiency of the personnel, thereby reducing the number of workers required.

Inspections, Tests, Analyses and Acceptance Criteria

No entries for this system.

2.5.9 Internal Pump Maintenance Facility

Design Description

The Reactor Internal Pump (RIP) maintenance facility is located in the reactor building and is designed for performing maintenance work on the RIP motor, including decontamination, in the assembled and disassembled states. The facility is equipped with all tools, cranes and fixtures needed for inspection of motor parts and motor heat exchanger tube bundles. Undervessel RIP handling tools are stored outside this area.

Inspections, Tests, Analyses and Acceptance Criteria

No entries for this system.

2.5.10 Fuel Cask Cleaning Facility

Design Description

This facility is located in two different areas of the plant.

The receiving area of the plant will have facilities for:

(1) Checking the cask for contamination.

(2) Cleaning the cask of road dirt.

(3) Inspection of the cask for damage.

(4) Attachment of the cask lifting yoke.

(5) Removal of head bolts and attachment of head lifting cables.

(6) Raising the cask to the refueling floor using the main building crane.

Upper Cask Cleaning Facility

The refueling floor will have facilities for:

(1) A deep drainable pit with gate acess to the storage pool.

(2) A under water area for the storage of the cask head and lifting yoke.

(3) A area for high pressure cleaning and decontamination. This area must be accessible for chemical and hand scrubbing, refastening the head andsmear tests.

Inspections, Tests, Analyses and Acceptance Criteria

No entries for this system

2.5.11 Plant Start-up Test Equipment

Design Description

No Tier 1 entry for this system.

2.5.12 Inservice Inspection Equipment

Design Description

A typical nuclear power plant facility utilizes a wide range of inservice inspection equipment much of which is equipment and materials used in performance of visual, surface and volumetric examinations required by the ASME Code, Section XI. Automated ultrasonic scanning equipment using multiple angle beam and straight beam transducers may be employed for volumetric examination of areas such as reactor pressure vessel welds and nozzle inner radii. The data from the automated examination is typically stored on optical disk or other appropriate recording media for subsequent computer-assisted data analysis. Manual ultrasonic examination equipment may be employed to supplement the automated examination if necessary or to perform the volumetric examination of areas such as ASME Class 2 vessel welds and nozzle inner radii. Manual ultrasonic examination equipment consists of an ultrasonic instrument containing analog or digital oscilloscope-style display and hand-held transducers. Where more than one angle beam examination is required due to the Class 2 vessel wall thickness, additional manual scans may be performed using ultrasonic transducers adjusted for the required angles of examination. Class 1 and 2 piping welds may be examined volumetrically using either computerized, automated ultrasonic scanning equipment or using manual ultrasonic examination equipment. Surface examinations of ferritic vessels and piping may be performed using the magnetic particle examination method with either prod or yoke type equipment. The magnetic particles may be either dry or may be in a wet suspension and may be either fluorescent or colored for viewing in visible light. Surface examinations of non-magnetic vessel and piping welds may be performed using either fluorescent or visible dye liquid penetrant materials. When fluorescent magnetic particles or liquid penetrant materials are used, portable ultraviolet lights are used for viewing. Eddy-current probe coils driven by automated scanning devices with computerized data acquisition systems may be substituted for surface examinations where the component configuration or radiation conditions render other surface examination techniques impractical or undesirable. Visual examinations of Class 1 and 2 bolting and component supports and attachments on Class 1, 2 and 3 piping and components may be conducted directly using simple aids such as mirrors and magnifying glasses. Remote visual examination equipment may be used for examination of interior surfaces of the reactor vessel and other components. Rigid fixtures are sometimes used as an aid in performance of the remote reactor visual examinations.

It is anticipated that these will be continuing beneficial advances in the technology of inservice inspection. As these enhanced technologies become available and proven, they will be applied (as appropriate) to inspection of the certified design.

Inspections, Tests, Analyses and Acceptance Criteria

No entries for this system.

2.6 REACTOR AUXILIARY

2.6.1 Reactor Water Cleanup System

Design Description

The CUW System removes particulate and dissolved impurities from the reactor coolant by recirculating a portion of the reactor coolant through a filter-demineralizer. The CUW System is designed to process a nominal flow of 2% of rated feedwater flow, and is designed for 87.9 kg/cm^{2}g and 302°C.

The CUW System removes excess coolant from the reactor system during startup, shutdown and hot standby. The excess water is directed to the radwaste or suppression pool. The CUW System also provides processed water to the reactor head spray nozzle for RPV cooldown.

The CUW System reduces RPV temperature gradients by maintaining circulation in the bottom head of the RPV during periods when the reactor internal pumps are unavailable.

The suction line through the PCPB contains two motor-operated isolation valves, which automatically close upon receipt of auto-isolation signal from the Leak Detection System and upon actuation of the SLC System. The auto-isolation signal from the LDS consists of the following signals:

(1) Low reactor water level.

(2) High ambient temperature in CUW equipment room.

(3) High temperature differential between the air conditioning duct and in the CUW equipment room.

(4) High flow differential between CUW System suction and discharge flows.

The suction valves (containment isolation valves) are designed to isolate against a maximum differential pressure of 87.9 kg/cm2d within 30 seconds. The inboard valve is powered from Class 1E Division 1 AC, while the outboard is fed from Class 1E Division 2 AC bus.

The CUW System is classified as a nonsafety system with a major portion of the system located outside of the primary containment pressure boundary (PCPB) and automatically isolatable. System piping and components within the PCPB, including the suction piping up to and including the outboard suction isolation valve, and containment isolation valves, including interconnecting piping, are ASME Section III, Seismic Category I, Quality Group A. All onsafety equipment is designed as Nonseismic, Quality Group C. Low pressure piping in the filter-demineralizer area, downstream of the high pressure block valves, is designed to Quality Group D.

The CUW System is a single closed loop system (Figure 2.6.1) that takes suction from the reactor vessel bottom head drain line or the shutdown cooling suction line connection to RHR loop "B". CUW flow passes through a regenerative heat exchanger (RHX) and two parallel nonregenerative heat exchangers (NRHX) to two pumps in parallel . The flow is discharged to two filter-demineralizers and returned through the regenerative heat exchanger to feedwater lines "A" and "B". Each pump, NRHX and filter-demineralizer is capable of 50% system capacity operation.

Each filter-demineralizer vessel is installed in an individual shielded compartment with provisions for handling filter material. Inlet, outlet, vent, drain and other process valves are located outside the filter-demineralizer compartment in a separate shielded area together with the necessary piping and associated equipment.

Process equipment and controls are arranged so that normal operations are conducted at a panel from outside the vessel or valve and pump compartment shielding walls.

Penetrations through compartment walls are designed so that they preclude direct radiation shine.

A remote, manually operated valve on the return line to the feedwater lines in the steam tunnel provides long-term leakage control and reverse flow isolation is provided by a check valve in the CUW piping.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.6.1 provides a definition of the instructions, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the CUW System.

Table 2.6.1: REACTOR WATER CLEANUP SYSTEM

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitments	Inspections, Test, Analysis	Acceptance Criteria
1. The configuration of the CUW System is shown in Figure 2.4.1.	1. Inspection of the as-built CUW configuration shall be performed.	1. As-built CUW System configuration conforms with Figure 2.6.1.
2. Suction line isolation valves automatically isolate the CUW System upon SLCS actuation, and receipt of auto-isolation signal from the Leak Detection System within 30 seconds.	2. Field test will be conducted to confirm that the CUW System will isolate upon SLCS actuation and receipt of leak detection signal by applying a simulated signal to the isolation logic circuit.	2. CUW isolates within 30 seconds when the SLC System is actuated or when leak detection limit is sensed by closing the primary containment pressure boundary isolation valves.
3. CUW suction valves are designed to close against the maximum design basis differential pressure.	3. Procurement records shall be reviewed and vendor to conduct shop test relating to valve operability during design basis condition.	3. Certified documentation demonstrates that the valves can close against a maximum differential pressure of 87.9 kg/cm^{2}d within 30 seconds.

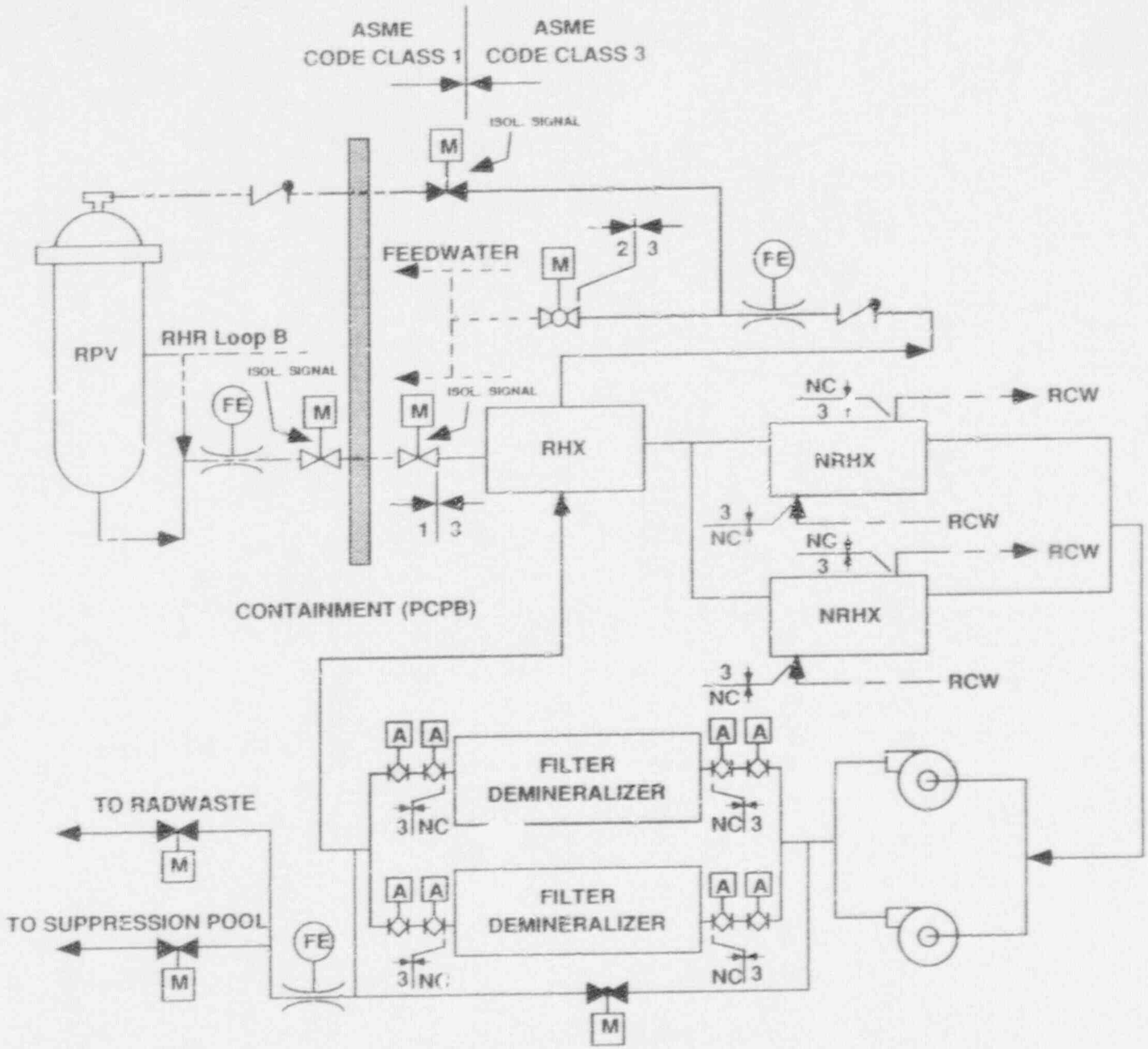


Figure 2.6.1 Reactor Water Cleanup (CUW) System P&ID

2.6.2 Fuel Pool Cooling and Cleanup System

Design Description

The Fuel Pool Cooling and Cleanup (FPC) System (Figure 2.6.2) removes decay heat generated by the spent fuel assemblies in the spent fuel storage pool. It also maintains the water quality and clarity by removing corrosion products, fission products, and other impurities from the pool. The system also monitors fuel pool water level and maintains a water level above the fuel sufficient to provide shielding for normal building occupancy.

The FPC System process water flows from the spent fuel storage pool through skimmer weirs into two surge tanks. It is drawn from the surge tanks by two circulating pumps arranged in parallel, and is subsequently discharged through a common header to two filter/demineralizer units arranged in parallel. The discharge water than flows through a common header to two heat exchangers arranged in parallel and cooled by reactor building cooling water system, and then returns to the spent fuel storage pool. A bypass line is provided around the filter/demineralizer portion of the system. Check valves are provided in the pool return lines to prevent the pools from siphoning in the event of pipe rupture.

The primary operational mode of the FPC System is cooling of the spent fuel pool under normal heat load conditions after a normal refueling operation. In this mode, initially both pumps, both heat exchangers, and both filter/demineralizer units are used. However, as fuel decay heat decreases, only one pump and one filter/demineralizer is used. The filter/demineralizer units may be bypassed in this mode. The pool temperature is kept at or below 52°C during this operating mode.

When the fuel pool is loaded with more than the normal fuel batch, the system operates in the maximum heat load operating mode. Since the decay heat in this mode exceeds the exchanged heat capacity of the FPC System heat exchangers, RHR System heat exchangers are used to supplement the FPC System heat exchangers. The FPC System operates with both pumps, both heat exchangers and both filter/demineralizer units along with two RHR heat exchangers. The pool temperature is kept at or below 60°C during this operating mode.

After an earthquake, the FPC System is operated with the filter/demineralizer units bypassed.

Normal makeup water to the spent fuel storage pool is provided by the non-safety-related Condensate (MUWC) Makeup System. A backup to the normal makeup system is also available from the nonsafety-related Suppression Pool Cleanup (SPCU) System. Additionally, an emergency safety-related, seismic category I makeup water to the spent fuel pool is provided via the FPC System connections to the Residual Heat Removal (RHR) System, which draws water from the suppression pool, a safety-related water source. The segment of the FPC System piping from the RHR System interface to the discharge of the fuel pool is safety-related.

The entire FPC System, with the exception of the filter/demineralizers, is designed to Seismic Category I and Quality Group C standards.

The system can be powered from either normal off-site sources or by the on-site power source.

The FPC System is located in the reactor building, a Seismic Category I, flood and tornadoe-missile protected structure.

The FPC System pumps are motor-driven centrifugal pumps supplying at least 250 m^3/hr at a head of 80m. A low suction pressure at the pump inlet will automatically stop that pump. The pump is also protected by an interlock for a low pump discharge flow. The FPC System heat exchangers are horizontal U-tube/shell type, each sized to provide a minimum heat transfer rate of 1.65×10^6 kcal/hr with a cooling water inlet temperature (shell side) of 35°C maximum, and the process water inlet temperature (tube side) of at least 52°C. The filter/demineralizer subsystem consists of filter and demineralizer units and supporting facilities for precoating of resin, backwashing, and waste removal.

The FPC System includes control room indication to allow for the monitoring and control during design basis operational conditions, i.e., system flows, temperatures, pressures, and pool water level, as well as valve open/close and pump on/off indication for those instruments and components shown on Figure 2.6.2, with the exception of check valves and manual valves.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.6.2 provides a definition of the inspections, tests and/or analyses together with associated acceptance criteria which will be undertaken for the FPC System.

Table 2.6.2: Fuel Pool Cooling and Cleanup System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the FPC System is shown in Figure 2.6.2.	1. Inspection of the as-built FPC System configuration shall be performed.	1. As-built FPC System configuration for those components shown conforms with Figure 2.6.2.
2. FPC pump is capable of delivering flow rate of ≥ 250 m^3/hr against 80m differential head.	2. Review of vendor design documents and test results relating to pump performance.	2. Installed pump meets design flow requirements.
3. The FPC System operates when powered from both normal off-site and on-site sources.	3. FPC System functional test shall be performed to demonstrate operation when supplied by either normal off-site power or from the on-site power source.	3. FPC System is capable of operating when supplied by either power source.
4. The FPC System mechanical equipment, excepting filter/demineralizer, is built to Seismic Category I and Quality Group C standards.	4. Procurement records and actual equipment shall be inspected to verify applicable FPC System components have been designed, manufactured and installed per the relevant standards.	4. Installed equipment meets the Seismic Category I requirements and Quality Group C standards.
5. Control room indications are provided for FPC System parameters.	5. Inspections shall be performed to verify presence of control room indication for the FPC System (Section 2.6.2).	5. The instruments are present in the control room as specified in Section 2.6.2.
6. The RHR System provides a safety-related makeup water source to the fuel pool.	6. The FPC and RHR Systems combined functional test shall be performed by aligning the system such that RHR draws water from the suppression pool and discharges into the fuel pool.	6. The combined system operation transfers makeup water from suppression pool to the fuel pool.

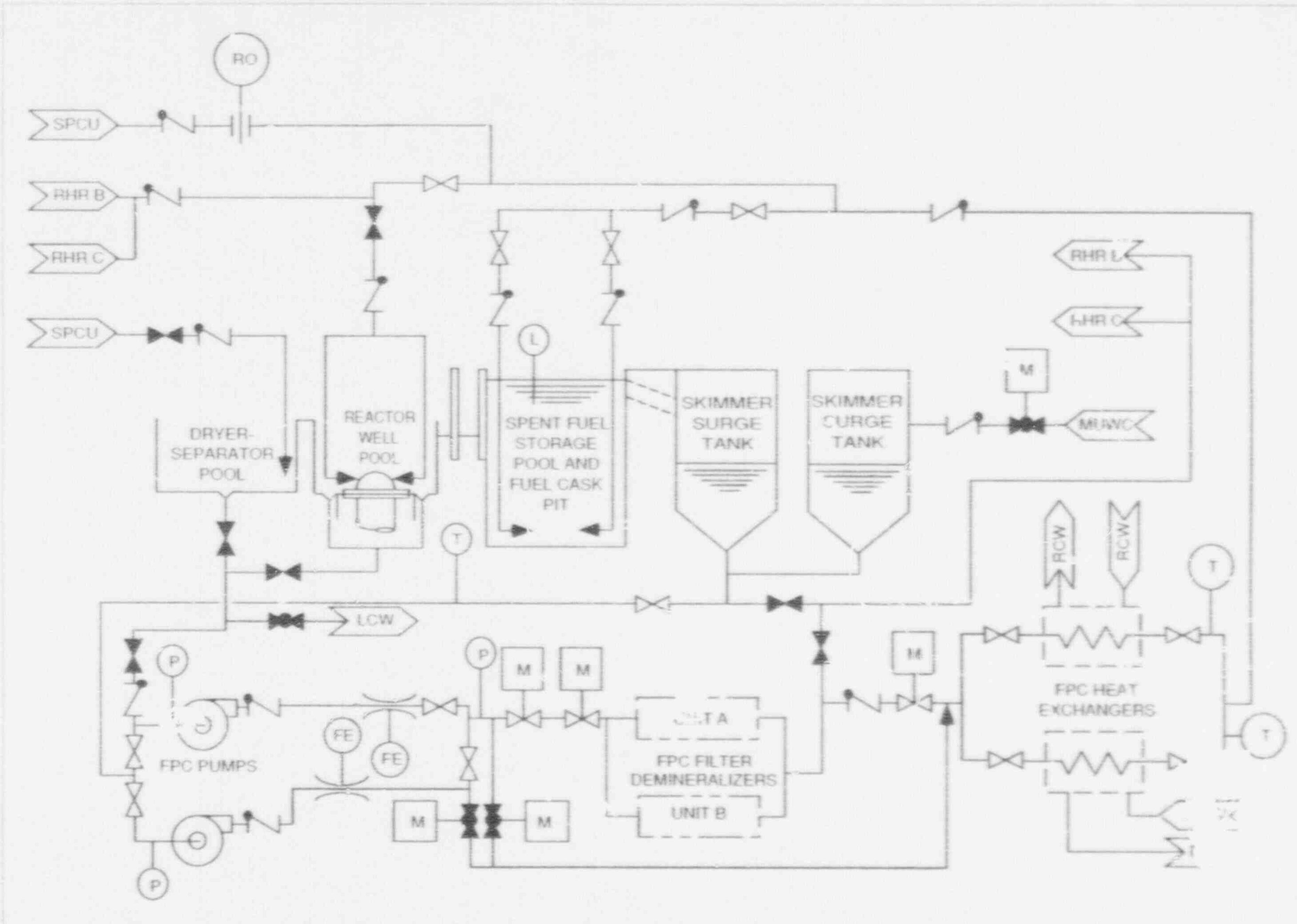


Figure 2.6.2 Fuel Pool Cooling and Cleanup (FPC) System

2.6.3 Suppression Pool Cleanup System

Design Description

The Suppression Pool Cleanup (SPCU) System provides a continuous purifying water treatment of the suppression pool. The system removes various impurities by filtration, adsorption and ion exchange processes. Water quality is maintained at a quality equal to that of the fuel and equipment pools.

Other functions of the SPCU system are:

(1) Provides makeup water to the spent fuel pool and to the Reactor Building Cooling Water (RCW) System surge tanks if the normal makeup (MUW) is not available.

(2) Provides water refill to the upper pools prior to refueling outage.

The SPCU System consists of a circulation piping, pump, valves, controls and instrumentation as shown in Figure 2.6.3. The SPCU pump draws approximately 250 m^3/hr (1100 gpm) of suppression pool water and directs it to the filter demineralizer (shared with the Fuel Pool Cooling and Cleanup system). Treated water from the filter demineralizer is then delivered either back to the suppression pool or to the upper pools via dryer/separator pit.

The SPCU System is a Seismic Category I system designed to provide makeup water to the spent fuel pool and the RCW surge tanks following a seismic or loss of offsite power event, if the normal makeup (MUW) is not available. During this mode, the filter demineralizer is bypassed and isolated. The SPCU pump takes makeup water from the Condensate Storage Tank (CST) and diverts it to the spent fuel pool and/or to the RCW surge tanks. Suppression pool water may also be used for makeup if a loss of coolant accident (LOCA) has not occurred. Power to the pump and associated valves for makeup after a seismic event will be connected to the emergency AC source.

The SPCU System has no safety related function except the primary containment isolation function. Following receipt of PCV isolation signals (low water level or high drywell pressure), the SPCU suction valves and discharge valve to the suppression pool are automatically closed to accomplish containment isolation function. The SPCU system suction valves will also close on low suppression pool water level signal. Containment isolation valves are safety related and are powered from redundant Class IE power sources.

The SCPU suction and return lines, from the containment up to and including the outboard isolation valve are classified as Seismic Category I and Quality Group B. The remainder of the piping system is classified as Seismic Category I

Quality Group C. The filter demineralizer portion is non-seismic Quality Group D.

The SPCU System design pressure and temperature are as follow:

	Design Conditions	
Component	Pressure	Temperature
Piping penetrating PCV up to the outboard isolation valve	3.16 kg/cm^2g (45 psig)	104°C (219°F)
Outboard isolation valves	16 kg/cm^2g (230 psig)	66°C (150°F)
SPCU pump, valves and the remainder of the piping system	19 kg/cm^2g (230 psig)	66°C (150°F)

The SPCU System is provided with instrumentation and controls to allow SPCU operation over the full range of normal plant operation.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.6.3 provides definition of inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the SPCU system.

Table 2.6.3: Suppression Pool Cleanup System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the SPCU System is shown in Figure 2.6.3.	1. Inspection of the as-built SPCU configuration shall be performed.	1. Verification of the as-built system is in conformance with the as-designed configuration (Figure 2.6.3).
2. The SPCU PCV isolation valves isolate upon receipt of auto isolation signals from the Leak Detection System.	2. Functional testing shall be performed on the system logic by simulating the auto isolation signal from the Leak Detection System.	2. Valves isolate upon receipt of auto isolation signal.
3. The SPCU pump capable of delivering makeup water to the spent fuel pool and to the RCW surge tanks.	3. The SPCU System functional tests shall be performed to demonstrate spent fuel pool and RCW surge tanks makeup.	3. The SPCU System delivering flow to spent fuel pool or RCW surge tanks with suction from the suppression pool and/or Condensate Storage Tank.
4. The SPCU System capability to operate on on-site emergency AC power source.	4. SPCU functional testing shall be performed to demonstrate operation when supplied from on-site emergency AC power.	4. Satisfactory SPCU operation with power supplied from on-site emergency AC power.

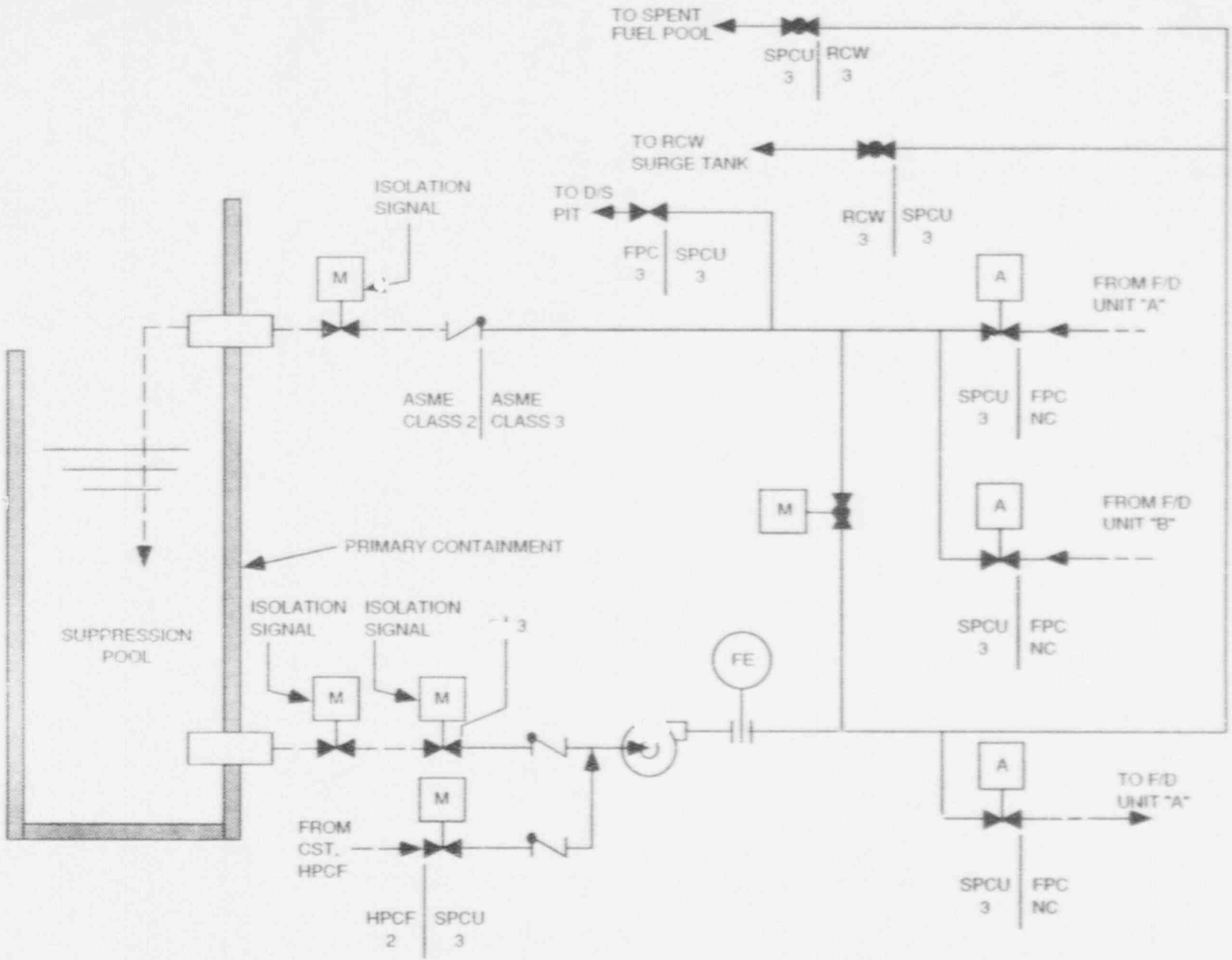


Figure 2.6.2 Suppression Pool Cleanup System

2.7 Control Panels

2.7.1 Main Control Room Panel

Design Description

The Main Control Room Panel is comprised of separate stand-alone modules (e.g., Main Control Panel, Large Display Panel). Each panel module is seismically qualified and provides grounding, and electrical independence and physical separation between safety divisions and between safety divisions and non-essential components and wiring.

Electrical power to divisional "Vital" components is from the Vital AC Control Power or battery of the same electrical division. Power to the non-essential "Vital" components is from the non-essential Vital AC Control Power or non-essential battery. Divisional, non-vital components are powered from the respective divisional AC Instrument Power and non-divisional, non-vital components are powered from non-essential AC Instrument Power.

The Main Control Room Panel and other main control room operator interfaces are designed to provide the operator with information and controls needed to safely operate the plant in all operating modes, including startup, refueling, safe shutdown, and maintaining the plant in a safe shutdown condition. The process to be used during the implementation stage will incorporate accepted Human Factor Engineering (HFE) principles in implementing the Main Control Room Human-System Interface (HSI).

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.7.1, together with the Design Acceptance Criteria (DAC) in Table 3.4, defines the design process to be used for the Main Control Room Panel and other main control room operator interfaces.

Table 2.7.1: Main Control Room Panels

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The Main Control Room Panels are seismically qualified.	1. Inspections of the as-built design documentation and installed equipment will be performed.	1. Panels are seismically qualified and installed.
2. The Main Control Room Panels design provides grounding and electrical independence and physical separation between divisions and between divisions and non-divisional components and wiring.	2. Inspections of the as-built design documentation and installed equipment will be performed.	2. Electrical Independence, and physical separation, and grounding of components and wiring is provided.
3. The Main Control Room Panel components identified as "Vital" are powered from their respective division or non-essential Vital AC Control Power or battery. Non-vital components are powered from their respective divisional or non-essential AC Instrument Power Supplies.	3. Inspections of installed equipment will be performed.	3. Panel components are powered from power supplies consistent with component classification and divisional assignment.
4. A Design and Implementation Process, directed by a dedicated Man-Machine Interface System (MMIS) Design Team, will govern the implementation of the Main Control Room Panel and other main control room operator interfaces. Human Factors Engineering principles will be employed to provide a Human-System Interface (HSI) for the Main Control Room Panels.	4. See Table 3.6.	4. Design and Implementation of the Main Control Room Panels and other main control room operator interfaces comply with the criteria defined in Section 3.6.

2.7.2 Radioactive Waste Control Panel

No entry. Covered by Item 2.9.1.

2.7.3 Local Control Panels

Design Description

Local panels, control boxes, and instrument racks are provided as protective housings and/or support structures for electrical and electronic equipment to facilitate system operations at the local level. They are designed for uniformity using rigid steel structures capable of maintaining structural integrity as required under seismic and plant dynamic conditions. The term "local panels" is assumed to include local control boxes in this document.

Local panels and racks used for plant protection systems are classified as Safety Related. They are located in a safety class structure in which there are no potential sources of missiles or pipe breaks that could jeopardize redundant modules. Each safety related panel/rack is seismic (Category I) qualified and provides grounding, and electrical independence and physical separation between safety divisions and non-essential components and wiring.

Electrical power to divisional panels/racks is from AC or DC power sources of the same division as that of each panel/rack itself. Power to the non-essential panels/racks is from the non-essential AC and/or DC sources.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.7.3 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the local control panels and racks.

Table 2.7.3: Local Control Panels and Racks

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analysis	Acceptance Criteria
1. The safety-related local panels and racks are seismic (Category I) qualified.	1. Inspection of the as-built design documentation and installed equipment will be performed.	1. Safety-related panels and racks are seismic (Category I) qualified and installed.
2. The design of local panels/racks provides grounding, electrical independence, and physical separation between divisions, and between divisions and non-divisional components and wiring.	2. Inspection of the as-built design documentation and installed equipment will be performed.	2. Electrical independence, physical separation, and grounding of components and wiring is provided.
3. Local panel/rack components are powered from their respective divisions or non-essential buses consistent with the panel/rack assignment.	3. Inspections of installed equipment will be performed.	3. Panel components are powered from power supplies consistent with component classification and divisional assignment.

2.7.4 Instrument Racks

No entry. Covered under Item 2.7.3.

2.7.5 Multiplexing

Design Description

Essential Multiplexing System

The Essential Multiplexing System (EMS) provides distributed data acquisition and control networks to support the monitoring and control of the plant standby safety systems. EMS comprises electrical devices and circuitry, such as Remote Multiplexing Units (RMUs), transmission lines, and Control Room Multiplexing Units (CMUs), that acquire data from remote process sensors and discrete monitors located within the plant and multiplex the signals to Safety System Logic and Control (SSLC) equipment in the main control room area. SSLC processes the input signals and multiplexes output control signals to the final actuators of driven equipment associated with safety systems.

EMS is divided into four divisions of equipment, each with independent control of data acquisition, multiplexing, and control output functions. System timing is asynchronous among the four divisions. No common clock signal is transmitted among the divisions of multiplexing and no timing signals are exchanged.

Both analog and discrete sensors are connected to RMUs in local areas, which perform signal conditioning, analog-to-digital conversion for continuous process inputs, change-of-state detection for discrete inputs, and message formatting prior to signal transmission. The RMUs are limited to acquisition of sensor data and the output of control signals. Trip decisions and other control logic functions are performed in SSLC processors in the main control room area. The RMUs transmit serial, time-multiplexed data streams representing the status of the plant variables via fiber optic cables to the control room CMUs. Data transmission is made over dual redundant channels. EMS design features automatic self-test and automatic reconfiguration after failure of one channel (either a cable break or device failure). The system returns to normal operation after reconfiguration within one full scan period. If an RMU or CMU has failed, that unit will be removed from service. Faults and their location are annunciated to the operator in the main control room.

The CMUs demultiplex the data and prepare the signals for use in interfacing controllers of SSLC or monitoring systems such as the process computer or display controllers. After the input data is processed in SSLC, the resulting trip logic decisions are transmitted (for Engineered Safety Features functions only) as a serial, time-multiplexed data stream via EMS to RMUs in the local areas, where the digital data is converted to contact closures or other signals for actuation of motor control centers or other device controllers. The data streams are dual redundant to prevent inadvertent ECCS equipment actuation after a hardware or software fault in one channel. The data reaching the RMUs is compared in 2-out-of-2 voting logic to confirm final output to the actuators.

Data can be transferred to non-safety systems for control or display through isolating fiber-optic data links and buffering devices (gateways or bridges, if required). Data transfer is made such that failures on the non-safety side cannot inhibit operation of safety-related logic functions. Data cannot be transmitted from the non-safety side to EMS.

EMS is capable of data transfer at rates sufficient to satisfy the system time response requirements of safety system functions. Data throughput capability shall be at least 10 megabits per second.

EMS starts and runs automatically upon application of system power, regardless of the sequence in which power is applied to individual controllers. EMS and SSLC automatically establish communications by detection of correct message passing. Logic is provided to prevent equipment activation outputs from occurring until stable plant sensor data and interlock permissive data are being received.

Loss of power causes a controlled transition to a safe-state without transients occurring that could cause inadvertent initiation or shutdown of driven equipment.

EMS equipment is classified as safety-related, Class 1E, and is seismically qualified.

Testability

EMS includes test facilities in the control room that will monitor data transmission to ensure that data transport, routing, and timing specifications are accurate. Bit error rate of each EMS network shall be better than 1 error in 10^{-9}. Out-of-tolerance parameters detected on-line for a particular input signal will result in an inoperative condition for that input into the trip logic processors of SSLC.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.7.5 provides a definition of the visual inspections, tests and analyses, together with associated acceptance criteria, which will be used by SSLC.

Table 2.7.5: Multiplexing

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Four divisions of independent and redundant EMS instrumentation acquire and transmit the safety-related sensor inputs and control functions of the plant standby safety systems and auxiliary supporting systems.	1. Visual inspection of the installed equipment will confirm the identity and location of EMS instrumentation, equipment panels, and their interconnections.	1. EMS configuration is in accordance with equipment arrangement shown in section 3.4, SSLC ITAAC. The figures indicate the required relationship of EMS to other safety system processing equipment.
2. EMS panels and processing equipment are Class 1E, safety-related, and seismically qualified.	2. Visual inspection of installed equipment, test records, and analyses based on equipment location will confirm the qualification status of EMS.	2. Installed configuration of EMS conforms to certified commitment.
3. The four divisions of redundant instrumentation are physically and electrically separated from each other. There are no interconnections among divisions of EMS. Data communications to the process computer or display controllers shall use an isolating transmission medium such as fiber optic cables.	3. Inspections of fabrication and installation records and construction drawings or visual field inspections of the installed EMS equipment will be used to confirm electrical and physical separation.	3. The installed EMS equipment conforms to certified commitment.
4. The RMUs and CMUs in each instrumentation division are powered independently from the divisional plant DC sources (Class 1E 125 VDC)	4. System tests will be conducted after installation to confirm that the electrical power supply configurations are in compliance with design commitments.	4. The installed instrument channels are operational with the power sources specified in the certified commitment.
5. EMS meets Electromagnetic Compatibility (EMC) requirements. Protection is provided against the effects of: a. Electromagnetic Interference (EMI) b. Radio Frequency Interference (RFI) c. Electrostatic Discharge (ESD) d. Electrical surge [Surge Withstand Capability (SWC)]	5. Factory tests for EMC will be conducted in a controlled environment on individual EMS equipment and on the integrated system configuration. EMC tests will also be conducted on the installed EMS configuration in the normal plant operating environment.	5. EMC performance of EMS is considered acceptable if tests confirm that electromagnetic fields, static discharges, and electrical surges do not affect system capability to acquire and condition data, transmit formatted data, receive control signals and send control outputs to final actuators.

Table 2.7.5: Multiplexing (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. EMS includes test facilities that will monitor data transmission to ensure that data transport, routing, and timing are accurate.	6. Preoperational tests will be conducted on the installed EMS equipment. These tests will confirm the basic functionality of each multiplexing component. The tests will include simulation of typical input parameters and monitoring of received these transmitted parameters. Random simulations will be used to test bit error rate, which shall be determined to be $<10^{-9}$.	6. Operability of the installed EMS equipment is considered acceptable under the following conditions (for each division): a. Monitored output signals match simulated input signals for accuracy of signal conversion and transmission time. b. Bit error rate is $<10^{-9}$. c. Simulated data errors are detected and annunciated to operator.
7. Full system test of EMS with SSLC and other interfacing systems connected confirms EMS response to safety system tests specified in each interfacing system ITAAC. Testing is conducted on the four divisions of EMS/SSLC simultaneously to verify 2-out-of-4 system operation.	7. Preoperational tests will be conducted to verify safety system logic functions of each interfacing safety system. These tests will verify support of SSLC and the safety systems for scram capability, containment isolation capability, and ECCS initiation capability. The tests will include demonstration of ability to meet stated delay times and maximum response times. Tests will be conducted such that each display, alarm, annunciator, or other status indicator for each system is shown to be functional. See section 3.4 SSLC ITAAC, item 7 for the scope and method of testing.	7. EMS support of the interfacing safety systems is considered acceptable if reactor trip, containment isolation, and ECCS response of the installed equipment meet the acceptance criteria stated in each interfacing system ITAAC. The response time of each control action and trip output is within performance limits of each interfacing system. Performance of SSLC for these same tests also confirms EMS performance.

Table 2.7.5: Multiplexing (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8. EMS provides safe-state response to loss of power source.	8. Tests will be conducted to verify that graceful degradation of EMS system outputs occurs upon momentary or long-term loss of one division of the DC power source or power to individual EMS components. Tests will also confirm that reinitialization of system or component after power is restored does not impair normal system function.	8. EMS response to loss of power is acceptable for the following conditions: a. Loss of one division of power does not cause false output trip or inadvertent initiation of final system actuators. Loss of power and loss of divisional trip signals are annunciated. b. Loss of power to individual component produces a safe-state output condition without extraneous false outputs (normally-energized outputs de-energize, normally-de-energized outputs remain de-energized). c. Restart (initialization) of component or system upon recovery of power does not cause inadvertent output action (outputs remain in safe-state condition
9. EMS is fault-tolerant in each division and provides capability for automatically reconfiguring after failure of an RMU, CMU, or interconnecting cable.	9. Preoperational tests will be conducted to verify that a single failure of a multiplexing component does not impair total system function. Faults will be simulated and the response monitored. Tests specified in item 6 will be repeated to confirm operability of network.	9. EMS response to instrument or cable failure is acceptable for the following conditions: a. A single cable break does not affect network operation. b. Loss of one RMU or CMU removes that unit from service; network continues normal operation. c. Fault occurrence and notice of reconfiguration is displayed to operator.

2.7.6 Local Control Box

No entry. Covered under Item 2.7.3.

2.8 Nuclear Fuel

2.8.1 Nuclear Fuel

Design Description (Including Loose Parts Monitoring)

Fuel design for the ABWR is not within the scope of the certified design. It is intended that the specific fuel to be utilized in any facility which has adopted the certified design be in compliance with U.S. NRC approved fuel design criteria. This strategy is intended to permit future use of enhanced/improved fuel designs as they become available. However, this approach is predicated on the assumption that future fuel designs will be extensions of the basic fuel technology that has been developed for boiling light water reactors. Key characteristics of this established LWR fuel technology are:

(1) Uranium oxide based fuel pellets.

(2) Zirconium-based (or equivalent) fuel cladding.

(3) All material selected on the basis of BWR operating conditions.

(4) Multi-rod fuel bundles in an N lattice.

(5) Fuel bundle inlet orificing to control bundle flow rates, core flow distribution, and reactor coolant hydraulic characteristics.

The following is a summary of the principal requirements which must be met by the fuel supplied to any facility utilizing the certified design.

The ABWR design provides a Loose Parts Monitoring System (LPMS) aimed at protecting the fuel against the potential effects of loose parts entrained in the reactor coolant flow. A discussion of the LPMS is included in this section.

General Criteria

(1) NRC-approved analytical models and analysis procedures are applied.

(2) New design features are included in lead test assemblies.

(3) The generic post-irradiation fuel examination program approved by NRC is maintained.

Thermal-Mechanical

The fuel design thermal-mechanical analyses are performed for the following conditions:

(1) Either worst tolerance assumptions are applied or probabilistic analyses are performed to determine statistically bounding results (i.e., upper 95% confidence).

(2) Operating conditions are taken to bound the conditions anticipated during normal steady-state operation and anticipated operational occurrences.

The fuel design evaluations are preformed against the following criteria:

(1) The fuel rod and fuel assembly component stresses, strains, and fatigue life usage are evaluated to not exceed the material ultimate stress or strain and the thermal fatigue capability.

(2) Mechanical testing is performed to ensure that loss of fuel rod and assembly component mechanical integrity will not occur due to fretting wear.

(3) The fuel rod and assembly component evaluations include consideration of metal thinning and any associated temperature increase due to oxidation and the buildup of corrosion products to the extent that these influence the material properties and structural strength of the components.

(4) The fuel rod internal hydrogen content is controlled during manufacture of the fuel rod consistent with ASTM standards.

(5) The fuel rod is evaluated to ensure that fuel rod bowing does not result in loss of fuel rod mechanical integrity due to boiling transition.

(6) Loss of fuel rod mechanical integrity will not occur due to excessive cladding pressure loading.

(7) The fuel assembly (including channel box), control rod and control rod drive are evaluated to assure control rods can be inserted when required. These evaluations consider the effect of combined safe shutdown earthquake (SSE) and loss-of-coolant accident (LOCA) loads.

(8) Loss of fuel rod mechanical integrity will not occur due to cladding collapse into a fuel column axial gap.

(9) Loss of fuel rod mechanical integrity will not occur due to pellet-cladding mechanical interaction.

Nuclear

(1) A negative Doppler reactivity coefficient is maintained for any operating condition.

(2) A negative core moderator void reactivity coefficient resulting from boiling in the active flow channels is maintained for any operating conditions.

(3) A negative moderator temperature coefficient is maintained above hot standby.

(4) For a super prompt critical reactivity insertion accident originating from any operating condition, the net prompt reactivity feedback due to prompt heating of the moderator and fuel is negative.

(5) A negative power coefficient, as determined by calculating the reactivity change, due to an incremental power change from a steady-state base power level, is maintained for all operating power levels above hot standby.

(6) The plant meets the cold shutdown margin requirement.

(7) The effective multiplication factor for fuel designs stored under normal and abnormal conditions is shown to meet fuel storage limits by demonstrating that the peak uncontrolled lattice k-infinity calculated in a normal reactor core configurations meets the limits for the storage racks.

Hydraulic

Flow pressure drop characteristics are included in the calculation of the Operating Limit MCPR.

Because of the channeled configuration of BWR fuel assemblies, there is no bundle-to-bundle cross-flow inside the core, and the only issue of hydraulic compatibility of various bundle types in a core is the bundle inlet flow rate variation and its impact on margin-to-thermal limits. The coupled thermal-hydraulic-nuclear analyses performed to determine fuel bundle flow and power distribution uses the various bundle pressure loss coefficients to determine the flow distribution required to maintain a total core pressure drop boundary condition to be applied to all fuel bundle. The margin to the thermal limits of each fuel bundle is determined using this consistent set of calculated bundle flow and power.

Loose Parts Monitoring System (Design Description)

The Loose Parts Monitoring System (LPMS) is designed to provide detection of loose metallic parts within the reactor pressure vessel. Detection of loose parts can provide the time required to avoid or mitigate safety-related damage to or malfunctions of primary system components. The LPMS detects structure borne sound that can indicate the presence of loose parts impacting against the reactor pressure vessel internals. The system alarms when the signal amplitude exceeds preset limits. The LPMS detection system can evaluate some aspects of selected signals. However, the system by itself will not diagnose the presence and location of a loose part. Review of LPMS data by an experienced LPM engineer is required to confirm the presence of a loose part.

The LPMS continuously monitors the reactor pressure vessel and appurtenances for indications of loose parts. The LPMS consists of sensors, cables, signal conditioning equipment, alarming monitor, signal analysis and data acquisition equipment, and calibration equipment. The alarm setting is set low enough to meet the sensitivity requirements, yet is designed to discriminate between normal background noises and the loose part impact signal to minimize spurious alarms.

The array of LPMS sensors consist of a set of sensor channels that are strategically mounted on the external surface of the primary pressure boundary at various elevations and azimuths at natural collection regions for potential loose parts. General mounting locations are at the a) main steam outlet nozzle, b) feedwater inlet nozzle, c) core spray nozzles, and d) control rod drive housings.

The online system sensitivity is such that the system can detect a metallic loose part that weighs between 0.25 lb to 30 lbs and impacts with a kinetic energy of 0.5 ft-lb on the inside surface of the reactor pressure vessel within 3 feet of a sensor. The LPMS frequency range of interest is typically from 1 to 10 kHz. Frequencies lower than 1 kHz are generally associated with flow induced vibration signals or flow noise.

The LPMS includes provisions for both automatic and manual start-up of data acquistion equipment with automatic activation in the event the preset alert level is reached or exceeded. The system also initiates an alarm to the control room personnel when an alert condition is reached.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.8.1a provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the fuel that will be proposed for the facility.

Tables 2.8.1b provides a definition of the inspections, tests and/or analyses together with associated acceptance criteria which will be undertaken for Loose Parts Monitoring System.

Table 2.8.1a: Nuclear Fuel

Inspections, Tests, Analyses and Acceptance Criteria

Design Criteria	Inspections, Tests, Analyses	Acceptance Criteria
1. Fuel design thermal-mechanical analyses are performed using either worst tolerance assumptions or probabilistic analyses to determine statistically bounding results (i.e., upper 95% confidence).	1. Manufacturing specifications and design drawings will be reviewed to ensure proper input parameters are used in the analyses.	1. The analyses are determined to be applicable to the fuel being used in the core.
2. Fuel design thermal-mechanical analyses are performed for operating conditions anticipated during normal steady-state operation and anticipated operational occurrences (AOOs).	2. Operating limits defining the maximum allowable fuel pellet operating power level as a function of fuel pellet exposure, will be established to ensure actual fuel operation is maintained within the analysis bases.	2. Evaluations demonstrate that the fuel satisfies specified acceptable fuel design limits for the applicable thermal limits (e.g., MAPLHGR).
3. The fuel rod and fuel assembly component stresses, strains, and fatigue life usage are evaluated to not exceed the material ultimate stress or strain and the thermal fatigue capability.	3. Exposure-dependent, thermal-mechanical analyses will be performed.	3. a. For stress or strain, the Design Ratio is ≤ 1.0, where Design Ratio = $\frac{\text{Effective Stress}}{\text{Stress Limit}}$ or $\frac{\text{Effective Strain}}{\text{Strain Limit}}$ b. For fatigue, the calculated fatigue duty is less than the material fatigue capability.
4. Mechanical testing is performed to ensure that loss of fuel rod and assembly component mechanical integrity will not occur due to fretting wear in an environment free of foreign material.	4. Testing or operating experience will be used to determine whether the fuel assembly is susceptible to significant fretting wear.	4. The testing or experience demonstrates that the fuel will not fail due to fretting.
5. The fuel rod and assembly component evaluations include consideration of metal thinning and any associated temperature increase due to oxidation and the buildup of corrosion products to the extent that these influence the material properties and structural strength of the components.	5. The effects of cladding oxidation and corrosion product buildup on the fuel rod surface will be included in the evaluations as appropriate.	5. The evaluations demonstrate the fuel design is adequate for resisting the effects of metal thinning and any associated temperature increases due to oxidation and corrosion product buildup.

Table 2.8.1a: Nuclear Fuel (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Design Criteria	Inspections, Tests, Analyses	Acceptance Criteria
6. The fuel rod internal hydrogen content is controlled during manufacture of the fuel rod.	6. A specification controlling the maximum amount of hydrogen allowed to be present in the manufactured fuel rod will be established.	6. The amount of hydrogen in the manufactured fuel rod is less than the specification.
7. The fuel rod is evaluated to ensure that fuel rod bowing does not result in loss of fuel rod integrity due to boiling transition.	7. A limit will be placed on the bundle power encoded in the plant process computer to prevent loss of mechanical integrity due to boiling transition.	7. Evaluations demonstrate that fuel rod bowing resulting in loss of fuel rod integrity does not occur for the bundle power limit.
8. Loss of fuel rod mechanical integrity will not occur due to excessive cladding pressure loading.	8. Evaluations will be performed to calculate the cladding creep-out rate due to internal gas pressure during normal steady-state operation, which will be compared to the instantaneous fuel irradiation swelling rate.	8. The evaluations indicate that the cladding creep-out rate is less than the fuel irradiation swelling rate.
9. The fuel assembly (including channel box), control rod and control rod drive are evaluated to assure control rods can be inserted when required.	9. Evaluations will be performed to assure that component deformations are not sever enough, and vertical uplift forces are not great enough to unseat the lower tie plate, to prevent control rod insertion.	9. The evaluations demonstrate that component deformations are not severe enough, and vertical uplift forces are not great enough, to prevent control rod insertion.
10. Loss of fuel rod mechanical integrity will not occur due to cladding collapse into a fuel rod column axial gap.	10. The fuel rod will be evaluated to ensure that cladding structural instability will not occur during normal operation.	10. The evaluations demonstrate that cladding creep collapse is not expected to occur.
11. Loss of fuel rod mechanical integrity will not occur due to pellet-cladding mechanical interaction.	11. The fuel rod will be evaluated to determine the maximum uniform cladding plastic strain during AOOs.	11. The calculated cladding circumferential plastic strain does not exceed 1% during AOOs.
12. A negative Doppler reactivity coefficient is maintained for any operating condition.	12. The Doppler reactivity coefficient will be calculated for an equilibrium core of the fuel design, at the limiting point in the cycle, and covering all expected modes of operation.	12. The calculated Doppler coefficient is negative.

Table _ 3.1a: Nuclear Fuel (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Design Criteria	Inspections, Tests, Analyses	Acceptance Criteria
13. A negative core moderator void reactivity coefficient resulting from boiling in the active flow channels is maintained for any operating condition.	13. The core moderator void reactivity coefficient will be calculated for an equilibrium core of the fuel design, at the limiting point in the cycle, and covering all expected modes of operation.	13. The calculated core moderator void reactivity coefficient is negative.
14. A negative moderator temperature coefficient is maintained above hot standby.	14. The moderator temperature coefficient will be calculated for an equilibrium core of the fuel design, at the limiting point in the cycle, and covering all expected modes of operation.	14. The calculated moderator temperature coefficient is negative above hot standby.
15. For a super prompt critical reactivity insertion accident originating from any operating condition, the net prompt reactivity feedback due to prompt heating of the moderator and fuel is negative.	15. The prompt reactivity feedback will be calculated for an equilibrium core of the fuel design, at the limiting point in the cycle, and covering all expected modes of operation.	15. The calculated prompt reactivity feedback is negative.
16. A negative power coefficient, as determined by calculating the reactivity change, due to an incremental power change from a steady-state base power level, is maintained for all operating power levels above hot standby.	16. The sign of the power coefficient will be determined for an equilibrium core of the fuel design, at the limiting point in the cycle, and covering all expected modes of operation.	16. The power coefficient is negative.
17. The plant meets the cold shutdown margin requirement.	17. The cold shutdown margin will be calculated each cycle for the most reactive condition with the most reactive control rod in the full-out position.	17. The calculated cold shutdown margin is greater than the value given in the Technical Specifications.
18. The effective multiplication factor for fuel designs stored under normal and abnormal conditions is shown to meet fuel storage limits.	18. The peak uncontrolled lattice multiplication factor will be calculated in the normal reactor core configuration or the effective multiplication factor of fuel stored under normal and abnormal conditions will be calculated.	18. The effective multiplication factor under normal conditions is less than 0.90 for regular density racks and less than 0.95 for high density racks, and less than 0.95 for abnormal conditions for regular and high density racks.

Table 2.8.1a: Nuclear Fuel (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Design Criteria	Inspections, Tests, Analyses	Acceptance Criteria
19. Flow pressure drop characteristics are included in the calculation of the Operating Limit Minimum Critical Power Ratio (OLMCPR).	19. Calculations of the OLMCPR will include flow pressure drop characteristics.	19. Flow pressure drop characteristics are verified as being included in the OLMCPR calculation.

Table 2.8.1b: Loose Parts Monitoring System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. An LPMS is provided with detectors located at natural collection regions for loose parts. The system includes the necessary signal processing and related equipment.	1. Visual inspections will be conducted of the as-built facility to confirm that the LPMS is in place and operational.	1. An LPMS has been provided.
2. The LPMS shall be capable of detecting a metallic loose part that weighs from 0.25 lb to 30 lbs and impacts with a kinetic energy of 0.5 ft-lb within 3 feet of each sensor.	2. System calibration tests will be performed to demonstrate system sensitivity.	2. It must be shown that the LPMS can detect a metallic loose part that weighs from 0.25 lb to 30 lbs and impacts with a kinetic energy of 0.5 ft-lb within 3 feet of each sensor.

2.8.2 Fuel Channel

Design Description

Fuel channel design for the ABWR is not within scope of the certified design. It is intended that the specific fuel channel to be utilized in any facility which has accepted the certified design be in compliance with U.S. NRC approved fuel channel design criteria. This strategy is intended to permit future use of enhanced/improved control rod designs as they become available. However, this approach is predicated on the assumption that future fuel channel designs will be extensions of the basic technology that has been developed for light water reactors. The key characteristic of this established BWR fuel channel technology is the use of zirconium-based (or equivalent) fuel channels which preclude cross-flow in the core region.

The following is a summary of the principal requirements which must be met by the fuel channel supplied to any facility using the certified design.

General Criteria

(1) The material of the fuel channel shall be shown to be compatible with the reactor environment.

(2) The channel will be evaluated to ensure that channel deflection does not preclude control rod drive operation.

(3) The effects of channel bow will be included in the fuel rod critical power evaluations.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.8.2 provides a definition of the inspection, tests and/or analyses together with associated acceptance criteria which will be undertaken for the fuel channel that will be proposed for the facility.

Table 2.8.2: Fuel Channel

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The material of the fuel channel shall be shown to be compatible with the reactor environment.	1. Testing or operating experience will be used to determine whether the fuel channel materials are compatible with the reactor environment.	1. The testing or experience demonstrates the materials are adequate.
2. The channel will be evaluated to ensure that channel deflection does not preclude control rod drive operation.	2. The channel will be evaluated to detemine the expected amount of channel deflection.	2. Calculated channel deflections are not of an amount great enough to preclude control rod insertion.
3. The effects of channel bow will be included in the fuel rod critical power evaluations.	3. An allowance will be included in the critical power calculation to account for the effects of channel bow.	3. Verification demonstrates that an allowance for channel bow is included in the fuel rod critical power evaluations.

2.8.3 Control Rod

Design Description

Control rod design for the ABWR is not within the scope of the certified design. It is intended that the specific control rod to be utilized in any facility which has adopted the certified design be in compliance with U.S. NRC approved control rod design criteria. This strategy is intended to permit future use of enhanced/improved control rod designs as they become available. However, this approach is predicated on the assumption that future control rod designs will be extensions of the basic technology that has been developed for light water reactors. Key characteristics of this established BWR control rod technology are:

(1) Control rods perform dual functions of power distribution shaping and reactivity control.

(2) The control rod has a cruciform cross-sectional envelope shape.

(3) The control rod has a coupling at the bottom for attachment to the control rod drive.

(4) The control rod has an upper bail handle for transporting.

(5) The cruciform cross section contains neutron poison materials which are either contained within or as part of the control rod structure.

The following is a summary of the principal requirements which must be met by the control rod supplied to any facility utilizing the certified design.

General Criteria

(1) The control rod stresses, strains, and cumulative fatigue shall be evaluated to not exceed the ultimate stress or strain of the material.

(2) The control rod shall be evaluated to be capable of insertion into the core during all modes of plant operation within the limits assumed in the plant analyses.

(3) The material of the control rod shall be shown to be compatible with the reactor environment.

(4) The reactivity worth of the control rod shall be included in the plant core analyses.

(5) Lead Surveillance program shall be implemented if a change in design features such as new absorber material or structural material not previously used in reactor cores could impact the function of the control rod.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.8.3 provides a definition of the inspection, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the control rod that will be proposed for the facility.

Table 2.8.3: Control Rod

Inspections, Tests, Analyses and Acceptance Criteria

Design Criteria	Inspections, Tests, Analyses	Acceptance Criteria
1. The control rod stresses, strains, and cumulative fatigue are evaluated to not exceed the ultimate stress or strain of the material.	1. Evaluations of loads due to shipping, handling, and expected operating modes will be performed.	1. The ultimate stress and strain limits are not exceeded, and cumulative fatigue does not exceed a fatigue usage factor of 1.0.
2. The control rod is evaluated to be capable of insertion into the core during all modes of plant operation within the limits assumed in the plant analyses.	2. Evaluations will be performed of the effects on control rod clearance of manufacturing tolerances and swelling and irradiation growth under expected operating modes.	2. Calculated control rod clearances are sufficient to permit insertion.
3. The material of the control rod shall be shown to be compatible with the reactor environment.	3. Testing or operating experience will be used to determine whether the control rod materials are compatible with the reactor environment.	3. The testing or experience demonstrates the materials are adequate.
4. The reactivity worth of the control rod shall be included in the plant core analyses.	4. Evaluations will be performed to determine the reactivity worth of the control rod.	4. The calculated cold shutdown margin is greater than the value given in the technical specifications.

2.9 Radioactive Waste

2.9.1 Radwaste System

Design Description

The liquid waste system collects, treats, monitors, and either recycles or discharges all radioactive liquid wastes within the plant. The solid waste system collects, sorts, monitors and either recycles or packages all radioactive solid wastes within the plant.

The radwaste system does not serve or support any safety function and has no safety design basis.

Liquid Waste System

The liquid waste system consists of three subsystems: the low conductivity waste system (LCW), the high conductivity waste system (HCW) and the detergent waste system (DW).

The LCW system collects and processes clean radwaste, i. e., water of relatively low conductivity. Equipment drains and backwash transfer water are typical of wastes found in this subsystem. These wastes are collected, treated and monitored. If quality is adequate, the water is sent to the condensate storage tank. If not, it is reprocessed.

The HCW system collects and processes dirty radwaste, i. e., water of relatively high conductivity and solids content. Floor drains are typical of wastes found in this subsystem. These wastes are collected, treated and monitored. If quality is adequate, the water is sent to the condensate storage tank. If not, it is reprocessed. Sometimes, the water is discharged following established procedures to maintain proper plant water balance.

The DW system collects and processes detergent waste from personnel showers and laundry operations. These wastes are collected, filtered and monitored. If quality is adequate, the water is discharged.

The liquid waste system provides one discharge line to the canal for the release of processed liquid waste. This line is provided with flow instrumentation, means of flow control and a radiation monitor. A high radiation signal from this monitor will close the discharge valve. The liquid waste system is provided with sample tanks to collect processed water with provisions to mix the contents and obtain samples for radiochemical analyses prior to discharge. Discharge can be made from only one sample tank at a time through a locked closed valve that is under administrative control.

Solid Waste System

The solid waste system consists of two subsystems: The dry active waste system (DAW) and the wet active waste system (WAW).

The DAW system has an area which is devoted to collecting and storing DAW and sorting it into reusable and nonreusable items. Reusable items are decontaminated as necessary and reused. Nonreusable items are separated for further treatment. Combustible DAW is burned in an incinerator. Incombustible and compressible DAW are reduced in volume using a compactor. The processed DAW is packaged for shipment.

The WAW system has tanks for collecting concentrated liquids, sludges or slurries and spent resins.

The concentrated liquids are dried and solidified.

The slurries and spent resins are either dried or dewatered.

Packaging and transporting of the packaged wastes are in conformance with 10CFR61 and 49CFR 173, Subpart 1. Radiation monitors are provided to survey all waste packages.

Individual components are provided with vents to assure that dust or contaminated air are not released to work spaces.

A Process Control Program shall be prepared and approved by the NRC demonstrating that the cement-glass process complies with 10CFR61, Section 61.56.

Table 2.9.1 provides a definition of the inspections, test and/or analyses together with associated acceptance criteria which will be used for the radwaste system.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.9.1 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be used for the radwaste system.

Table 2.9.1: Radwaste System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The liquid waste system has only one discharge line provided with flow instrumentation, means of flow control and a radiation monitor. A high radiation signal from this monitor will stop the discharge. Discharge can be made from only one sample tank at a time.	1. The as-built discharge line and controls shall be inspected and tested.	1. The as-built discharge line and controls shall operate as designed.
2. The components of the liquid waste system shall be provided which meet the codes and standards in Table 1, Regulatory Guide 1.143.	2. Inspections, tests and analyses shall be performed as required on all as-built system components.	2. All components shall meet the required codes and standards.
3. Means shall be provided to package and transport the solid wastes in conformance with 10CFR61 and 49CFR173, Subpart 1.	3. As-built equipment for packaging and transporting solid wastes shall be inspected, tested, and analyzed.	3. The analysis shall show that the as-built means of packaging and transporting solid wastes can meet the requirements of the regulatory guides.
4. Individual components shall be properly vented to prevent the release of dust or contaminated air to work spaces.	4. The as-built components shall be inspected to show that the release of air-borne radioactivity has been prevented by venting.	4. All as-built components have been properly vented.
5. A Process Control Program has been developed and approved for the cement-glass solidification system.	5. An inspection shall show that an approved PCP is available and the as-built equipment is capable of being operated in conformance with the PCP.	5. A Process Control Program has been approved by the NRC and the as-built equipment is suitable for operation following the PCP.

2.10 Power Cycle

2.10.1 Turbine Main Steam System

Design Description

The Main Steam (MS) System (Figure 2.10.1) supplies steam generated in the reactor to the turbine. This Tier 1 entry addresses that portion of the MS System that ranges between, but does not include, the outermost containment isolation valves and the turbine stop valves.

The MS System is not required to effect or support safe shutdown of the reactor or to perform in the operation of rector safety features; however, the MS System is designed:

(1) To comply with applicable codes and standards in order to accommodate operational stresses such as internal pressure and dynamic loads without risk of failures and consequential releases of radioactivity in excess of the established regulatory limits.

(2) To accommodate normal and abnormal environmental limits.

(3) To assure that failures of non-Seismic Category I equipment or structures, or pipe cracks or breaks in high or moderate piping in the MS will not preclude functioning of safety-related equipment or structures in the plant.

(4) With suitable access to permit in-service testing and inspections.

The MS System main steam piping consists of four lines from the outboard main steamline isolation valves to the main turbine stop valves. The header arrangement upstream of the turbine stop valves allows them to be tested on-line with minimum load reduction and also supplies steam to the power cycle auxiliaries, as required.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.10.1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which sill be undertaken for the MS System.

Table 2.10.1:

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Failures of non-Seismic Category I equipment or structures, or pipe cracks or breaks in high or moderate piping in the MS System will not preclude functioning of safety-related equipment or structures in the plant.	1. Visual inspection of the MS System will be performed.	1. No safety-related systems or structures are in the vicinity or are protected from failures in the nonseismic portions of the MS System.
2. Access is provided for in-service testing and inspections.	2. Visual inspection of the MS System will be performed.	2 Confirmation that required in-service inspections can be accomplished.

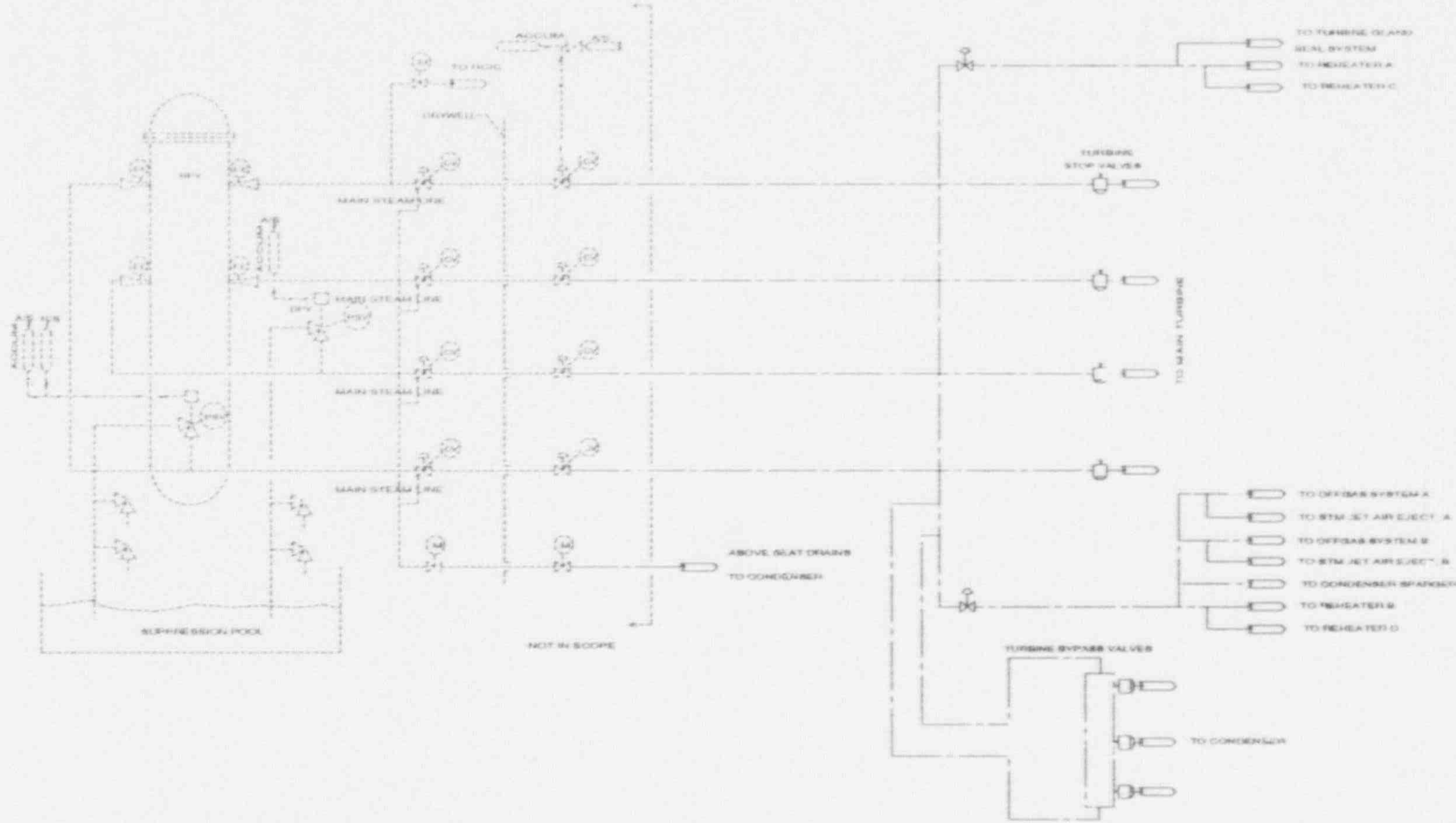


Figure 2.10.1 Main Steam System

2.10.2 Condensate Feedwater and Condensate Air Extraction System

The Condensate Feedwater and Condensate Air Extraction System (CFDWA) consists of two subsystems, the Condensate and Feedwater System and the Main Condenser Evacuation System (MCES).

Condensate and Feedwater System

Design Description

The function of the Condensate and Feedwater (CF) System is to receive condensate from the condenser hotwells, supply condensate to the cleanup system, and deliver high purity feedwater to the reactor, at the required flow rate, pressure and temperature. Condensate is pumped from the main condenser hotwell by the condensate pumps, passes through the feedwater heaters to the feedwater pumps, and then is pumped through the high pressure heaters to the nuclear Steam Supply System.

The CF System boundaries considered here extend from the main condenser outlet to (but not including) the second isolation valve outside the containment. The CF System consists of the piping, valves, heat exchangers, controls and instrumentation, and the associated equipment and subsystems which supply the reactor with heated feedwater in a closed steam cycle utilizing regenerative feedwater heating.

The CF System does not serve or support any safety function and has no safety design basis. System analyses show that failure of this system cannot compromise any safety-related systems or prevent safe shutdown.

Portions of the system that are radioactive during operation are shielded with access control for inspections.

Leakage is minimized with welded construction used wherever practicable.

Relief discharges and operating vents are channeled through closed systems.

Operational system redundancy is provided with respect to feedwater heaters, pumps, or control valves by using multi-string arrangements and provisions for isolating and bypassing equipment and sections of the system.

The majority of the condensate and feedwater piping considered in this section is located within the turbine building which contains no safety-related equipment or systems. The portion which connects to the second isolation valve outside the containment is located in the steam tunnel between the turbine and reactor buildings. This portion of the piping is analyzed for dynamic effects from postulated events and safety/relief valve discharges.

The entire system piping is analyzed for waterhammer loads that could potentially result from anticipated flow transients.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.10.2a provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the CF System.

Main Condenser Evacuation System

Design Description

Noncondensable gases are removed from the power cycle by the Main Condenser Evacuation (MCE) System (Figure 2.10.2). The MCE System removes the hydrogen and oxygen produced by the radiolysis of water in the reactor, and other power cycle noncondensable gases, and exhausts them to the offgas system during plant power operation, and to the turbine building compartment exhaust system at the beginning of each startup.

The MCE System does not serve or support any safety function and has no safety design basis.

The MCE System is designed to Quality Group D.

The MCE System consists of two 100% capacity, double stage, steam jet air ejectors (SJAE) units (complete with intercondenser) for power plant operation, and a mechanical vacuum pump for use during startup. The last stage of the SJAE unit is normally in operation and the other is on standby.

Steam supply to the second stage ejector is maintained at a minimum specified flow rate to ensure adequate dilution of the hydrogen and prevent the offgas from reaching the flammable limit of hydrogen.

Steam pressure and flow is continuously monitored and controlled in the ejector steam supply lines. Redundant pressure controllers sense steam pressure at the second stage inlet and modulate the steam supply control valves upstream of the air ejectors. The steam flow transmitters provide inputs to logic devices. These logic devices provide for isolating the offgas flow from the air ejector unit on a two-out-of-three logic, should the steam flow drop below acceptable limits for offgas stream dilution.

The vacuum pump exhaust stream is discharged to the turbine building compartment exhaust system which provides for radiation monitoring of the system effluents prior to their release to the monitored vent stack and the atmosphere.

The vacuum pump is tripped and its discharge valve is closed upon receiving a main steam high-high radiation signal.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.10.2b provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the MCE System.

Table 2.10.2a: Condensate and Feedwater System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The CF System will be analyzed to show that system failure will not compromise plant safety.	1. Review failure analysis design assumptions with respect to as-built condition.	1. As-built conditions are same as the design assumptions used in the analysis.
2. The CF System will be provided with shielding and access control.	2. Visual inspection of the CF System will be performed.	2. The as-built CF System provides shielding and access control.
3. CF System leakage will be minimized by use of welded construction wherever practicable.	3. Visual inspection of the CF System will be performed.	3. Welded construction utilized as designed.
4. CF System relief valve discharges and operating vents will be channeled through closed systems.	4. Visual inspection of the CF System will be performed.	4. Relief valve discharges and operating vent lines are routed as required by certified design.
5. The CF System will operate with a feedwater heater, pump or control valve out-of-service.	5. Simulated signals to verify operational status maintained.	5. The CF System remains operational.
6. Failures of nonseismic Category I equipment or structures, or pipe cracks and breaks in high- or moderate piping in the CF System will not preclude functioning of safety-related equipment or structures in the plant.	6. Visual inspection of the CF System will be performed.	6. No safety-related systems or structures are in the vicinity or are protected from failure in the nonseismic portions of the CF System.
7. The CF System will be analyzed for potential waterhammer loads.	7. Review waterhammer analysis design assumptions with respect to as-built condition.	7. As-built conditions are same as the design assumptions used in the analysis.

Table 2.10.2b: Main Condenser Evacuation System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The offgas will be prevented from reaching a flammable limit of hydrogen.	1. Tests will be conducted using simulated signals to the SJAE flow control system.	1. Confirmation that the system isolates before flammability limits are reached.
2. Radioactive releases will be maintained within established limits.	2. Tests will be conducted using simulated signals to the vacuum pump isolation system.	2. Confirmation that the system isolates as required to limit releases.

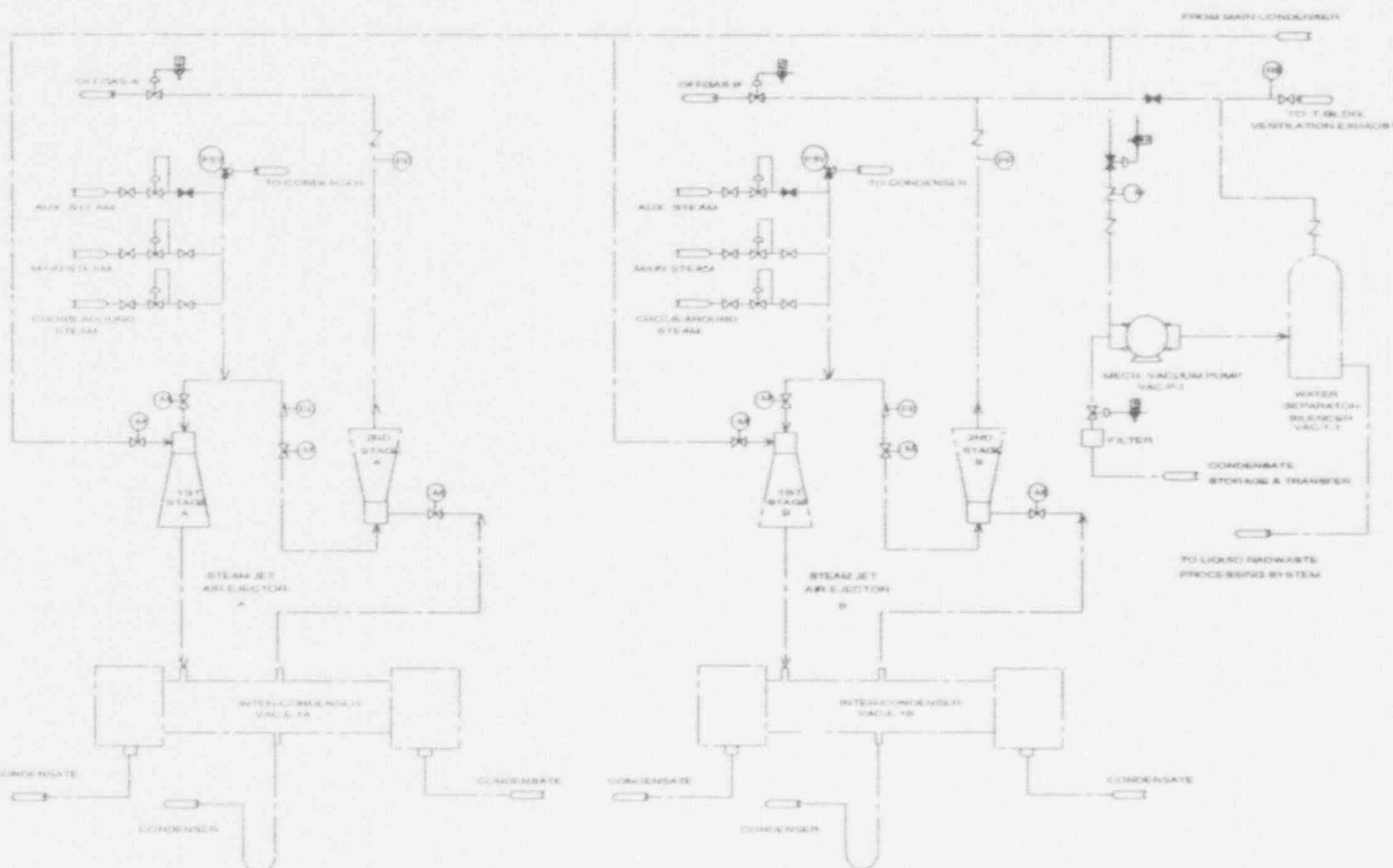


Figure 2.10.2 Main Condenser Evacuation System

2.10.3 Heater Drain and Vent System

No Tier 1 entry for this system.

2.10.4 Condensate Purification System

Design Description

The Condensate Purification (CP) System purifies and treats the condensate as required to maintan reactor feedwater purity, using filtration to remove corrosion products, ion exchange to remove condenser leakage and other impurities, and water treatment additions to minimize corrosion/erosion releases in the power cycle.

The CP System does not serve or support any safety function and has no safety design basis.

The CP System is designed to Quality Group D standards.

The CP System consists of full flow high efficiency particulate filters followed by full flow deep bed demineralizers.

Shielding is provided for the CP System.

Vent gases and other wastes from the CP System are collected in controlled areas and sent to the radwaste system for treatment and/or disposal.

The CP System is located in the turbine building, and piping or equipment failures will not affect plant safety.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.10.4 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the CP System.

Table 2.10.4: Condensate Purification System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Shielding will be provided for the CP System.	1. Visual inspection of the as-built CP System will be performed.	1. Installed equipment is shielded in accordance with certified design.
2. NO safety-related equipment will be in the vicinity of the CP System.	2. Visual inspection of the as-built CP System will be performed.	2. Equipment is located as specified by certified design.
3. CP System wastes will be collected in controlled areas.	3. Visual inspection of the as-built CP System will be performed.	3. Compliance with certified design commitment.

2.10.5 Condensate Filter Facility

No entry. Covered by Item 2.10.4.

2.10.6 Condensate Demineralizer

No entry. Covered by Item 2.10.4.

2.10.7 Main Turbine

Design Description

The main Turbine Generator (TG) System converts the energy in steam from the nuclear steam supply system into electrical energy.

The TG System does not serve nor support any safety function and has no safety design basis. However, the TG System is a potential source of high energy missiles that could damage safety related equipment or structures.

The TG System is designed to prevent overspeed and thus minimize the possibility of high energy missile generation from TG System moving parts.

The following component redundancies are employed to guard against overspeed:

(1) Main stop valves/Control valves.

(2) Intermediate stop valves/Intercept valves (CIVs).

(3) Primary speed control/Backup speed control.

(4) Fast acting solenoid valves/Emergency trip fluid system (ETS).

(5) Speed control/Overspeed trip/Backup overspeed trip.

The TG System is enclosed within the turbine building, which contains no safety-related equipment or structures. The turbine generator is orientated within the turbine building to be inline with the reactor and control buildings to minimize the potential for any high energy TG System generated missiles from damaging any safety-related equipment or structures.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.10.7 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the TG System.

Table 2.10.7: Main Turbine Generator System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The TG System will be designed to prevent the turbine generator rotor from exceeding the design overspeed with redundant instrumentation, controls and valving such that a single failure of any component will not cause the rotor speed to exceed its design value.	1. Visual inspection of the installed equipment together with simulated testing of the as-built overspeed protection system.	1. Design provisions to prevent overspeed are in place.
2. The turbine building will contain no safety-related equipment or structures. The turbine generator will be orientated to minimize the potential for low trajectory high energy TG System missiles from damaging safety-related equipment or structures.	2. Visual inspection of the as-built turbine building and plant arrangements.	2. Turbine generator arrangements per approved plant design.

2.10.8 Turbine Control System

No entry. Covered under Item 2.10.7.

2.10.9 Turbine Gland Steam System

Design Description

The Turbine Gland Sealing (TGS) System prevents the escape of radioactive steam from the turbine shaft/casing penetrations and valve stems and prevents air inleakage through subatmospheric turbine glands.

The TGS System consists of a sealing steam pressure regulator, sealing steam header, a gland steam condenser, with two full capacity exhaust blowers, and the associated piping, valves and instrumentation.

The TGS System does not serve or support any safety function and has no safety design basis.

The TGS System is designed to Quality Group D standards.

The outer portion of all glands of the turbine and main steam valves is connected to the gland steam condenser, which is maintained at a slight vacuum by the exhauster blower. During plant operation, the gland steam condenser and one of the two installed 100% capacity motor-driven blowers are in operation. The exhauster blower to the turbine building compartment exhaust system effluent stream is continuously monitored prior to being discharged.

During normal operation, the steam seal header is supplied from the main steam path. The auxiliary steam system provides a 100% steam supply backup when high radiation levels are detected in the blower exhaust or the main steam path source(s) are unavailable.

A site specific radiological analysis will be required to determine what actions and at what level the TGSS steam supply should be switched to the auxiliary source.

Relief valves on the seal steam header prevent excessive seal steam pressure.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.10.9 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the TGS System.

Table 2.10.9: Turbine Gland Steam System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Radiological releases will be maintained within established limits.	1. Visual inspection of the installed equipment coupled with a site-specific radiological analysis and simulated signals to verify that the TGS System switches to auxiliary steam on high radiation levels.	1. System switches to auxiliary steam as required to limit radiological releases.

2.10.10 Turbine Lubricating Oil System

No Tier 1 entry for this system.

2.10.11 Moisture Separator Heater

No Tier 1 entry for this system.

2.10.12 Extraction System

No Tier 1 entry for this system.

2.10.13 Turbine Bypass System

Design Description

The Turbine Bypass (TB) System provides capability to discharge main steam from the reactor directly to the condenser to minimize step load reduction transients effects on the reactor coolant system. The system is also used to discharge main steam during reactor hot standby and cooldown operations.

The TB System does not serve or support any safety function and has no safety design basis.

There is no safety-related equipment in the vicinity of the TB System. All high energy lines of the TB System are located in the turbine building and no failure of high energy lines in the TB System will affect safety related equipment.

The TB System consists of (1) a three-valve chest that is connected to the main steamlines upstream of the turbine stop valves, and (2) three dump lines that connect separately each regulating valve outlet to one condenser shell. The TB System is designed to bypass nominally 33% of the rated main steam flow directly to the condenser.

The TB System, in combination with the reactor systems, provides the capability to shed 40% of the turbine-generator rated load without reactor trip.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.10.13 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the TB System.

Table 2.10.13: Turbine Bypass System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Failure of high energy lines in the TB System will not affect safety-related equipment.	1. Visual inspection of the installed TB System will be conducted.	1. Confirmation that high energy line breaks will not jeopardize any safety-related equipment.

2.10.14 Reactor Feedwater Pump Driver

No entry. Covered under Item 2.10.2.

2.10.15 Turbine Auxiliary Steam System

No Tier 1 entry for this system.

2.10.16 Generator

No entry. Covered under Item 2.10.7.

2.10.17 Hydrogen Gas Cooling System

No Tier 1 entry for this system.

2.10.18 Generator Cooling System

No Tier 1 entry for this system.

2.10.19 Generator Sealing Oil System

No Tier 1 entry for this system.

2.10.20 Exciter

No Tier 1 entry for this system.

2.10.21 Main Condenser

Design Description

The main condenser is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the Turbine Bypass (TB) System.

The main condenser does not serve or support any safety function and has no safety design basis. It is, however, designed with necessary shielding and controlled access to protect plant personnel from radiation.

The main condenser is a multi-shell type deaerating unit with a shell located directly beneath each of the low pressure turbines. Each shell has tube bundles through which circulating water flows. The condensing steam is collected in the condenser hotwells (the lower shell portion) which provide suction to the condensate pumps.

Since the main condenser operates at a vacuum, any leakage is into the shell side of the main condenser. Tubeside or circulating water inleakage is detected by measuring the conductivity of sample water extracted beneath the tube bundles. In addition, conductivity is continuously monitored at the discharge of the condensate pumps and alarms provided in the main control room.

In all operational modes, the condenser is at vacuum and consequently no radioactive releases can occur. Loss of vacuum sequentially leads to control room alarm, turbine trip and eventually bypass and main steam isolation valve closure to prevent condenser overpressurization. Additionally, to avoid a turbine trip on high condenser backpressure reactor recirculation runback is automatically initiated and, on a site specific basis setting, on a combination of high condenser backpressure and loss of a circulating water pump.

Ultimate overprotection is provided by rupture diaphragms on the turbine exhaust hoods.

The instrumentation and control features that monitor the performance to ensure that the condenser is in the correct operating mode include:

(1) Hotwell Water Level—Automatically controlled within preset limits. During normal full load operation with nominal hotwell levels, the main condenser provides a four-minute active condensate storage volume and has a two-minute surge capacity. At minimum normal

operating hotwell water level, and normal full load condensate flow rate, the condenser provides a two minute minimum holdup time for N-16 decay.

(2) Condenser Pressure—Key overall performance indicator that initiates alarms and trips at preset levels.

(3) Low Pressure Turbine Exhaust Hood Temperature—Automatically initiates turbine exhaust water sprays to protect the turbine.

(4) Inlet and Outlet Circulating Water Temperature—Monitors performance only

(5) Conductivity within the condenser and at the discharge of the condensate pumps—Initiates alarms at preset levels.

The main condenser potential for flooding is less than the Circulating Water (CW) System and, consequently flooding protection is the same as the CW System (2.10.23). Condenser pressure indicators are located above any potential flood level.

Spray pipes and baffles are designed to protect the main condenser internals from high energy flow inputs.

Hydrogen buildup during operation is provided by continuous evacuation of the main condenser. Hydrogen sources are excluded during shutdown.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.10.21 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the main condenser.

Table 2.10.21: Main Condenser

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Overpressurization of the condenser will be prevented by condenser isolation from high energy sources.	1. Tests will be performed using simulated signals to verify that the system isolates.	1. System isolation occurs.
2. Condenser pressure indicators and transmitters will be located above any potential flood levels.	2. Visual inspections of the as-built system will be conducted.	2. Installed equipment is in compliance with the design commitment.
3. Shielding and controlled access shall be provided for the main condenser.	3. Visual inspections of the as-built system will be conducted.	3. Installed equipment meets the shielding and access control provisions of the certified design.

2.10.22 Off-Gas System

Design Description

The function of the Off-Gas System (OGS) is to treat the gas exhausted from the main turbine condensers, via the Steam Jet Air Ejectors (SJAE), to control and minimize the release of gaseous radioactivity discharged to the plant environment.

The OGS includes redundant hydrogen/oxygen catalytic recombiners and ambient temperature charcoal beds for process gas volume reduction and radionuclide retention/decay. All of the OGS equipment, shown in Fig. 2.10.3, is located in the turbine building.

Although the OGS is a non-safety-related system, the OGS is capable of withstanding an internal hydrogen explosion and is designed to ASME Boiler and Pressure Vessel Code Section VIII-Division 1 and ANSI B31.1 Piping Code.

The OGS design includes leakage limits, internally through valve seats and externally into the plant, to reduce radioactive releases through or out of the system.

The OGS processes the SJAE discharge during plant startup and normal plant operation before discharging the air flow to the plant vent.

The OGS charcoal beds can operate in one of three modes:

(1) Bypass - All OGS flow bypasses the charcoal beds (used during startup).

(2) Guard Bed - All OGS flow passes through the Guard Bed only.

(3) Adsorber Beds - All OGS flow passes through the Guard Bed and then through 4 parallel pairs of adsorber beds— each pair consisting of two beds in series.

Hydrostatic tests of the OGS components and entire OGS is performed at the factory and in the plant in accordance with the applicable requirements for ASME VIII and ANSI B31.1.

The OGS design parameters are:

Design Pressure	350 psig
Recombiner Shell Design Temperature	450°F
Normal Flow Rate (after recombiner)	15 scfm
Startup Flow Rate (after recombiner)	250 scfm
Input Gas Activity	100,000 uCi/sec

Automatic operation of the OGS caused by high radiation levels downstream of the charcoal bed discharge is as follows:

(1) High radiation will provide an alarm.

(2) High-high radiation will change the process gas flow path from bypass to flow through the charcoal beds.

(3) High-high-high radiation will shut the offgas discharge valve.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.10.22 provides a definition of the inspections, tests and/or analyses together with associated criteria which will be undertaken for the OGS.

Table 2.10.22: Off-Gas System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. System configuration of the OGS as described in Section 2.10.22 is shown on Figure 2.10.22.	1. Visual field inspections will be conducted of the installed OGS key components identified in Section 2.10.22 and Figure 2.10.3.	1. The installed configuration of the OGS will be considered acceptable if it complies with Figure 2.10.22 and Section 2.10.22.
2. The OGS is designed to withstand internal hydrogen explosions.	2. A hydrostatic test of the OGS will be conducted in the plant in accordance with the ASME VIII-1 and ANSI B31.1 requirements.	2. The hydrostatic test results must conform with the ASME and ANSI requirements.
3. The OGS is designed to minimize radioactive leakage through the OGS valve seats and externally into the plant.	3. Leak tests will be performed according to ANSI NDE Testing Standards.	3. The leak test results must conform with the ANSI requirements.
4. The OGS automatically controls the OGS flow bypassing or through the charcoal adsorber beds depending on the radioactivity levels in the OGS process gas downstream of the charcoal beds.	4. Preop tests will be performed as follows: a. A simulated high charcoal gas discharge radioactivity signal will give a Main Control Room (MCR) alarm. b. If the OGS process gas flow is bypassing the charcoal beds, a simulated high-high charcoal gas discharge radioactivity signal will close the bypass valve and direct the gas flow through the charcoal beds. c. If a simulated OGS gas discharge radioactivity signal reaches a high-high-high level, the charcoal bed discharge valve will close.	4. a. A Main Control Room alarm will be sounded on an OGS discharge line high radiation signal. b. The OGS charcoal bed bypass valve operates correctly on a high-high OGS discharge radioactivity signal. c. The OGS discharge valve closes on a high-high-high OGS discharge radioactivity signal.

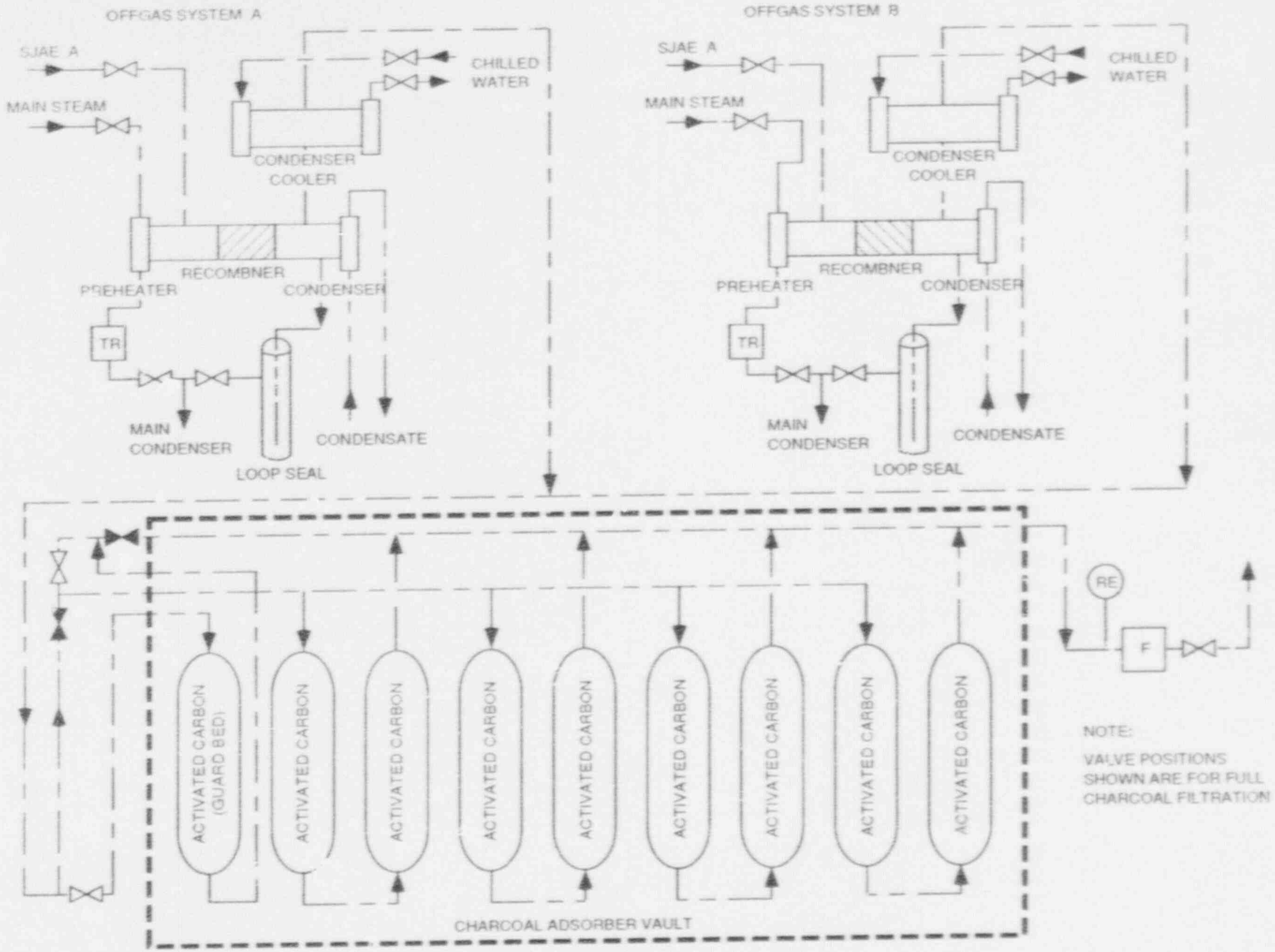


Figure 2.10.22 Off -Gas System

2.10.23 Circulating Water System

Design Description

The Circulating Water (CW) System provides a continuous supply of cooling water to the main condenser to remove the heat rejected by the turbine cycle and auxiliary systems.

The CW System does not serve or support any safety function and has no safety design basis.

To prevent flooding of the turbine building, the CW System is designed to automatically isolate in the event of gross system leakage. The circulating water pumps are tripped and the pump and condenser valves are closed in the event of a system isolation signal from the condenser area high-high level switches. A condenser area high level alarm is provided in the control room.

A reliable logic scheme will be adopted to minimize potential for spurious isolation trips (e.g., 2-out-of-3 logic).

The CW System is designed and constructed in accordance with Quality Group D specifications.

The CW System consists of the following components (Figure 2.10.23):

(1) Intake screens located in a screen house

(2) Pumps

(3) Condenser water boxes

(4) Piping and valves

(5) Tube-side of the main condenser

(6) Water-box fill and drain subsystem

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.10.23 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the CW System.

Table 2.10.23: Circulating Water System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Flooding of the turbine building will be prevented by CW System isolation in the event of gross system leakage.	1. Visual inspection of the installed equipment coupled with the analyses of the leakage/flooding characteristics of the as-built CW System will be performed using simulated signals to verify system isolates on high level.	1. CW System isolates upon receipt of an isolation signal.

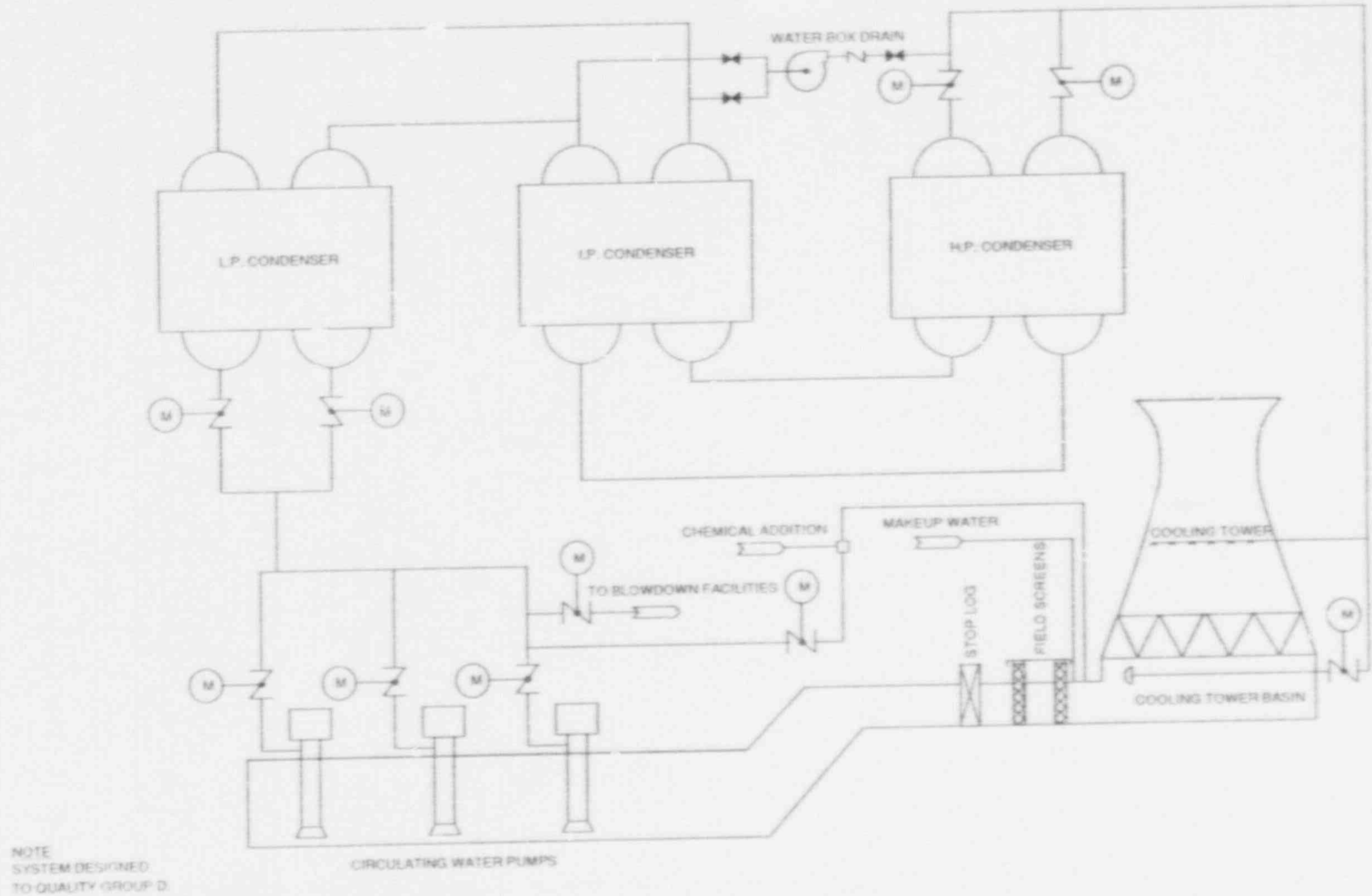


Figure 2.10.23 Circulating Water System

2.10.24 Condenser Cleanup Facility

No Tier 1 entry for this system.

2.11 Station Auxiliary

2.11.1 Ma. 'Vater (Purified) System

Desigr. Description

The Makeup Water (Purified) System (MUWP) provides purified makeup water to the condensate storage tank, plant auxiliary systems and the surge tanks shared by the reactor cooling water and HVAC emergency cooling water systems.

The MUWP system consists of distribution piping and valves to system users throughout the plant. Plant structures that have MUWP piping are shown in Figure 2.11.1. Makeup water is supplied to the system by the Makeup Water (Preparation) system located outside the turbine building. (The preparation system is not within the scope of the certified design; see Section 4.6 for interface requirements.)

The interfaces between the MUWP system and all safety-related systems are located in the control building or reactor building which are Seismic Category I structures. The portions of the MUWP system that could adversely impact structures, systems, or components important to safety during a seismic event are designed to assure their integrity under seismic loading resulting from a safe shutdown earthquake. In the event of a LOCA, the safety-related systems are isolated from the MUWP system by automatic valves in the safety-related system.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.1 provides a definition of the inspections, tests and/or analyses together with associated acceptance criteria which will be undertaken for the MUWP system.

Table 2.11.1: Makeup Water (Purified) System (MUWP)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The MUWP distribution piping is provided for all principal building structures as shown in Figure 2.11.1.	1. Visual inspections of the MUWP penetrations into and out of all principal building structures as shown in Figure 2.11.1 shall be performed.	1. MUWP piping is provided to each of the principal building structures as shown in Figure 2.11.1.
2. The MUWP system purified water is provided by the makeup water (preparation) system.	2. Visual inspection of the MUWP system and makeup water (preparation) system interface connections shall be performed.	2. The MUWP and makeup water (preparation) system connections are provided.
3. The MUWP system provides makeup water to the surge tanks shared by the reactor cooling water and HVAC emergency cooling water systems.	3. Visual inspections of the surge tank and MUWP connections shall be performed.	3. The MUWP and surge tank connections are provided.

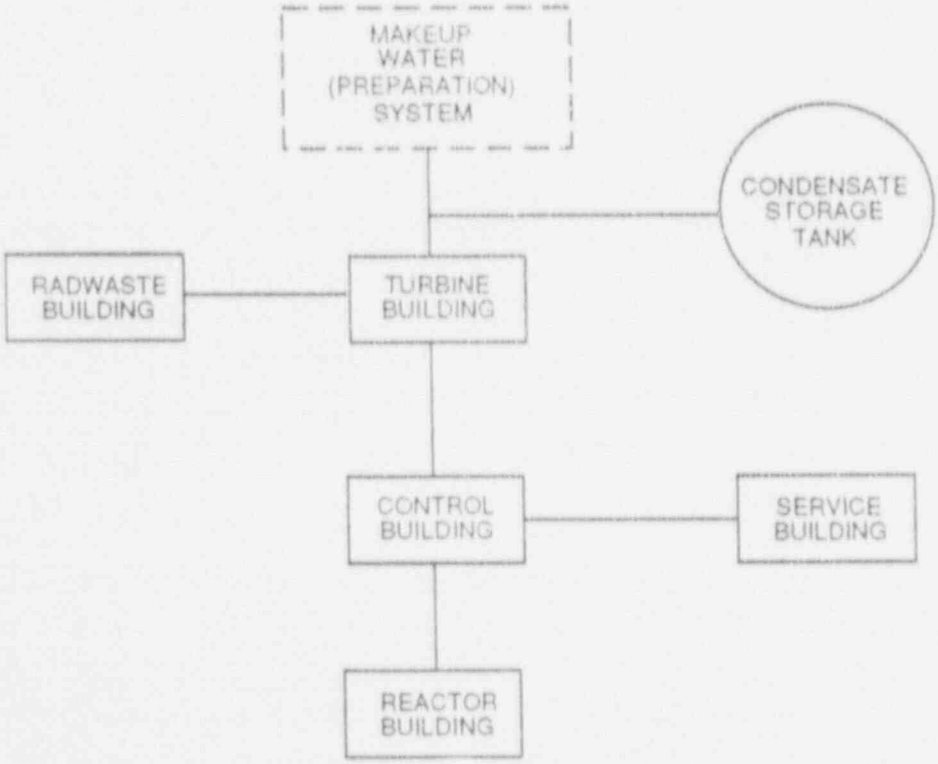


Figure 2.11.1 MUWP System

2.11.2 Makeup Water (Condensate) System

Design Description

The Makeup Water (Condensate) System (MUWC) provides condensate quality water to various plant systems for both normal and emergency operations.

The MUWC system consists of a condensate storage tank, three parallel pump units, and distribution piping and valves to system users throughout the plant. In addition to the MUWC pumps, the reactor core isolation cooling (RCIC), control rod drive (CRD), high pressure core flooder (HPCF) and suppression pool cleanup (SPCU) pumps take suction from the condensate storage tank. Makeup water is supplied to the tank from the makeup water (purified) system, control rod drive system, radwaste system and the condensate return line.

Condensate storage tank water level is indicated both locally and in the main control room. Alarms are also provided in the main control room for high water level. Any tank overflow or drainage is sent to the radwaste system for treatment.

The MUWC distribution piping connection to the condensate storage tank is located at a tank elevation that ensures adequate water supply to the HPCF, RCIC and SPCU which are connected at a lower elevation. In the event of a break in the MUWC piping, the water volume below the tank connection is sufficient to provide makeup water to these essential systems.

The primary MUWC system requirements are:

Condensate Storage Tank:	
Total Volume (gal.)	560,000 (approx.)
Essential Volume (gal.) (Below MUWC pump lines)	> 220,000 (approx.)
MUWC Pumps:	
Quantity	3
Capacity Each (gpm)	550

The MUWC system is not safety-related. However, the system incorporates features that assure reliable operation over the full range of normal plant conditions.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.2 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the MUWC system.

Table 2.11.2: Makeup Water (Condensate) System (MUWC)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analysis	Acceptance Criteria
1. The condensate storage tank has adequate capacity for plant requirements.	1. Visual inspections of the condensate storage tank volume will be performed.	1. The condensate storage tank has a total capacity of approx. 560,000 gallons. The essential volume below the MUWC pump line connection is > 220,000 gallons (approx.).
2. The MUWC pumps provide adequate flow to meet system and plant requirements.	2. Inspections of vendor documentation will include pump capacities. Flow tests will confirm that adequate flow is available to the system.	2. Each of the three MUWC pumps is capable of delivering 550 gpm to the system.
3. Condensate storage tank water level indication and alarms are provided in the main control room.	3. Visual inspection of the control room water level indication and alarm equipment will be performed.	3. Condensate storage tank water level indication and alarms are provided in the main control room.

2.11.3 Reactor Building Cooling Water System

Design Description

The Reactor Building Cooling Water (RCW) System distributes cooling water during various plant operating modes, as well as during shutdown, and during post-LOCA operation of the various safety systems. The system removes heat from plant auxiliaries and transfers it to the Ultimate Heat Sink (UHS) via the Reactor Service Water (RSW) System. The RCW System removes heat from the ECCS equipment including the emergency diesel generators during a safe reactor shutdown cooling function.

The RCW system is designed to perform its required safe reactor shutdown cooling function following a postulated loss-of-coolant accident/loss-of-offsite power (LOCA/LOOP), assuming a single active failure in any mechanical or electrical RCW subsystem or RCW support system. In case of a failure which disables any one of the three RCW divisions, the other two divisions meet plant safe shutdown requirements, including a LOCA or a LOOP, or both.

Redundant isolation valves are able to separate the essential portions of the RCW cooled components from the nonsafety-related RCW cooled components during a LOCA, to assure the integrity and safety functions of the safety-related parts of the system. The isolation valves to the non-essential RCW System are automatically or remote-manually operated, and their positions are indicated in the main control room.

Each RCW division includes two pumps which circulate RCW through the various equipment cooled by the RCW System and through three heat exchangers which transfer the RCW heat to the UHS via the RSW System.

Each RCW division Main Control Room (MCR) instrument indication includes main loop surge tank level, main loop radiation and RHR HX flow and temperature. MCR control includes all MOVs and AOVs shown on Figure 2.11.3. Normal surge tank MUWP makeup is automatic or MCR controlled.

The three RCW train configurations are shown on Figure 2.11.3. The RCW System provides three similar complete trains (A, B and C) which are mechanically and electrically separated. The RCW pumps and valves for each RCW division are supplied electrical power from a different division of the ESF power system.

The RCW ASME Code classifications for different portions of the system are indicated on Figures 2.11.3a-c. The safety-related portions of the RCW divisions are designed to Seismic Category I and Quality Group C, and are located Seismic Category I structures.

During various plant operating modes, one RCW water pump and two heat exchangers are normally operating in each division. Flow balancing provisions are included within each RCW division.

Pump design parameters are:

	RCW A/B	RCW C
Design pressure (psig)	200	200
Design temperature (°F)	158	158
Discharge flow rate (gpm/pump)	≥ 5,700	≥ 4,800
Pump total head (psig)	≥ 80	≥ 75
Heat exchanger capacities are each:	≥ $45E^6$ Btu/h	≥ $42E^6$ Btu/h

Connections to a radiation monitor are provided in each division to detect radioactive contamination resulting from a tube leak in one of the RHR exchangers, fuel pool exchangers, or other exchangers.

The RCW pumps and heat exchangers are located in the lower floors of the control building. The equipment cooled by the RCW divisions are located in the reactor building, turbine building, and radwaste building, (Figures 2.11.3a-c). Tables 2.11.3b, c, d show which equipment receives RCW flow during various plant operating and emergency modes. The tables also indicate how many heat exchangers are in service in each mode.

During normal plant operation, RCW flows through equipment which is normally operating and requires cooling and all ECCS equipment, except RHR heat exchangers and ESF diesel generators, as shown by open or closed valves in Figure 2.11.3.

If a LOCA occurs, a second RCW pump and third heat exchanger in each loop are placed in service. Automatic or remote operated isolation valves will separate the RCW for the LOCA required safety equipment from the nonsafety-related equipment, if a RCW surge tank low water level signal occurs. The primary containment RCW isolation valves automatically close if a LOCA occurs.

After a LOCA, the following sequence will be followed:

(1) If the nonsafety portion of the RCW System is available to the instrument air/service air (IA/SA) compressors, the CRD pumps and CUW pumps, RCW flow to these nonsafety components is maintained (Figure 2.11.3). Flow is automatically shutoff to other non-essential equipment after the LOCA.

(2) If the operator determines after the LOCA, from essential RCW instrumenta[illegible]n, that the integrity of the non-safety RCW System to the above-mentioned compressors and pumps has been lost, he can shut the remote operated non-essential isolation valves shown in Figure 2.11.3.

If the surge tank water level reaches a low level, with or without LOCA, indicating loss of water out of the RCW System, isolation valves in the supply and return piping to the non-essential equipment will automatically close, including the compressors and pumps mentioned above. Without a LOCA and with low surge tank standpipe water level, all running RCW pumps trip. For post-LOCA, both RCW pumps continue running with low surge tank standpipe water level.

The RCW/RSW heat exchanger design basis condition occurs during post-LOCA cooling of the containment via the RHR heat exchangers.

The RCW pumps have the flow capacity to deliver required flow to the ECCS equipment in each division and the above-mentioned compressors and pumps if the isolation valves cannot be closed.

After a LOOP, the RCW pumps isolation valves and their control logic are automatically powered by the emergency diesel generators.

A separate surge tank is provided for each RCW division. Normal makeup water source to the surge tank is the Makeup Demineralized Water (MUWP) System. For LOCA conditions, the Suppression Pool Cleanup (SPCU) System provides a backup surge tank water supply.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.3a provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be and undertaken for the RCW System.

Table 2.11.3a: Reactor Building Cooling Water (RCW) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. System configuration, including key components and flow paths, is shown in Figure 2.11.3.	1. Inspection of construction records will be performed. Visual inspection (VI) will be performed based on Figure 2.11.3.	1. The system configuration conforms with Figure 2.11.3.
2. Three RCW trains are mechanically and electrically independent.	2 Tests and VI of the three independent trains will be conducted which will include independent and coincident operation of the three trains to demonstrate complete divisional separation.	2. Plant tests and VI confirm proper independence of three RCW divisions.
3. During various modes of operation, the RCW System has adequate hydraulic capability for plant auxiliaries and the primary containment required for safe shutdown following a design accident or transient. These safe shutdown requirements are satisfied with only any 2 of 3 RCW divisions operating.	3. Limited system hydraulic tests will be conducted according to available nonnuclear heat plant conditions. The tests will demonstrate a safe plant shutdown with one RCW division out of service.	3. The results confirm that the RCW has the water flow capability specified by the certified design commitment, including safe shutdown operation with 1 RCW division out of service.
4. Isolation valves as shown in Figure 2.11.3 can automatically or remote manually separate the RCW for the essential equipment from the RCW for the non-essential equipment.	4. VI of the installed RCW System and RCW preoperational tests as follows will be completed: a. Remote-manual operation of the isolation valves from the main control room. b. During simulated LOCA conditions, a simulated LOCA condition will be combined with a simulated RCW surge tank water level signal to automatically close the isolation valves. c. A LOCA signal will shut RCW isolation valves which will shut off RCW flow to all non-essential equipment except the IA/SA compressors, CRD pumps and CUW pumps.	4. Isolation valves are properly located as shown in Figure 2.11.3 and are demonstrated to operate automatically or remote manually to isolate RCW for non-essential from RCW for essential equipment cooled by the RCW System.

Table 2.11.3a: Reactor Building Cooling Water (RCW) System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. Without LOCA and with low surge tank standpipe water level, both RCW pumps in that division trip. For post LOCA, both RCW pumps will operate with low surge tank standpipe water level.	5. RCW System preoperational tests will be performed as follows: a. Simulate a surge tank standpipe low water level in the standpipe and confirm the running pump(s) trip. b. During a simulated LOCA condition and a simulated surge tank standpipe low water level signal, confirm that both RCW pumps will operate. c. During low surge tank standpipe water level condition, a simulated LOCA signal starts both divisional RCW pumps.	5. The RCW pumps will trip or operate as follows: a. The running pump(s) will trip on surge tank standpipe low water level. b. With a LOCA condition signal, both RCW pumps will continue to operate with a simulated surge tank standpipe low water level signal. c. Both RCW pumps start on simulated LOCA signal.
6. A LOCA will result in the automatic start of the second RCW pump in each division and start flow through the third RCW/RSW Hx in each division. During LOCA/LOOP (loss-of-coolant accident/loss of off-site power) conditions, RCW pumps and valves are powered by the emergency diesel generators (D/G).	6. Tests simulating LOCA/LOOP conditions will be conducted for the RCW System which confirm the RCW and its support systems will perform its function under those conditions. Tests will be conducted for the RCW, which confirm that after the LOOP, each division of RCW pumps and valves operates with the same division of emergency D/G power and associated DC control power sources.	6. LOCA/LOOP signal successfully starts second RCW pump and initiates RCW/RSW Hx flow in each division including the following confirmations: a. Regardless of which RCW pump was operating during normal operation before the LOCA, after the LOAC/LOOP simulation occurs, the first and second RCW pump will start automatically, powered by the emergency diesel generator. b. Regardless of which two RCW/RSW Hx's were operating before the LOCA, after the LOCA/LOOP occurs, the RCW motor-operated valve on the third Hx discharge will open automatically.

Table 2.11.3b: Reactor Building Cooling Water Consumers
Division A

Operating Mode/ Components	Normal Operating Conditions	Shutdown at 4 hours	Shutdown at 20 hours	Hot Standby (no loss of AC)	Hot Standby (loss of AC	Emergency (LOCA) (Suppression Pool at 97°C)
RCW/RSW Heat Exchangers In Service	2	3	3	2	3	3
ESSENTIAL	(1)					
Emergency Diesel Generator A	--	--	--	--	X	X
RHR Heat Exchanger A	--	X	X	--	X	X
FPC Heat Exchanger A	X	X	X	X	X	X
Others (essential)(2)	X	X	X	X	X	X
NON ESSENTIAL						
RWCU Heat Exchanger	X	X	X	X	X	--
Inside Drywell(3)	X	X	X	X	X	--
Others (non-essential)(4)	X	X	X	X	X	X

(1) (X) = Equipment receives RCW in this mode.
(-) = Equipment does not receive RCW in this mode.
(2) HECW refrigerator, room coolers (FPC pump, RHR, RCIC, SGTS, FCS, CAMS), RHR motor and seal coolers.
(3) Drywell (A & C) and RIP coolers.
(4) Instruments and service air coolers; RWCU pump cooler, CRD pump oil, and RIP Mg sets.

Table 2.11.3c: Reactor Building Cooling Water Consumers Division B

Operating Mode/ Components	Normal Operating Conditions	Shutdown at 4 hours	Shutdown at 20 hours	Hot Standby (no loss of AC)	Hot Standby (loss of AC	Emergency (LOCA) (Suppression Pool at 97°C)
RCW/RSW HeatExchangers in Service	2	3	3	2	3	3
ESSENTIAL	(1)					
Emergency Diesel Generator B	--	--	--	--	X	X
RHR Heat Exchanger B	--	X	X	--	X	X
FPC HeatExchanger B	X	X	X	X	X	X
Others (essential)(2)	X	X	X	X	X	X
NON-ESSENTIAL						
RWCU Heat Exchanger	X	X	X	X	X	--
Inside Drywell(3)	X	X	X	X	X	--
Others (non-essential)(4)	X	X	X	X	X	X

(1) (X) = Equipment receives RCW in this mode.
(-) = Equipment does not receive RCW in this mode.
(2) HECW refrigerator, room coolers, (FPC pump, RHR, RCIC, SGTS, FCS, CAMS), RHR motor and seal coolers.
(3) Drywell (B) and RIP coolers.
(4) Reactor Building sampling coolers; LCW sump coolers (in drywell and reactor building), RIP MG sets and RWCU pump coolers.

Table 2.11.3d: Reactor Building Cooling Water Consumers Division C

Operating Mode/ Components	Normal Operating Conditions	Shutdown at 4 hours	Shutdown at 20 hours	Hot Standby (no loss of AC)	Hot Standby (loss of AC	Emergency (LOCA) (Suppression Pool at 97°C)
RCW/RSW HeatExchangers In Service	2	3	3	2	3	3
ESSENTIAL	(1)					
Emergency Diesel Generator B		--	--	--	X	X
RHR Heat Exchanger B	--	X	X	--	X	X
Others (essential)(2)	X	X	X	X	X	X
NON-ESSENTIAL						
Others (non-essential)(3)	X	X	X	X	X	X

(1) (X) = Equipment receives RCW in this mode.
(-) = Equipment does not receive RCW in this mode.

(2) HECW refrigerator, room coolers, motor coolers, and mechanical seal coolers for RHR and HPCF.

(3) Instrument and service air coolers, CRD pump oil cooler, radwaste components, HSCR condenser, and turbine building sampling coolers.

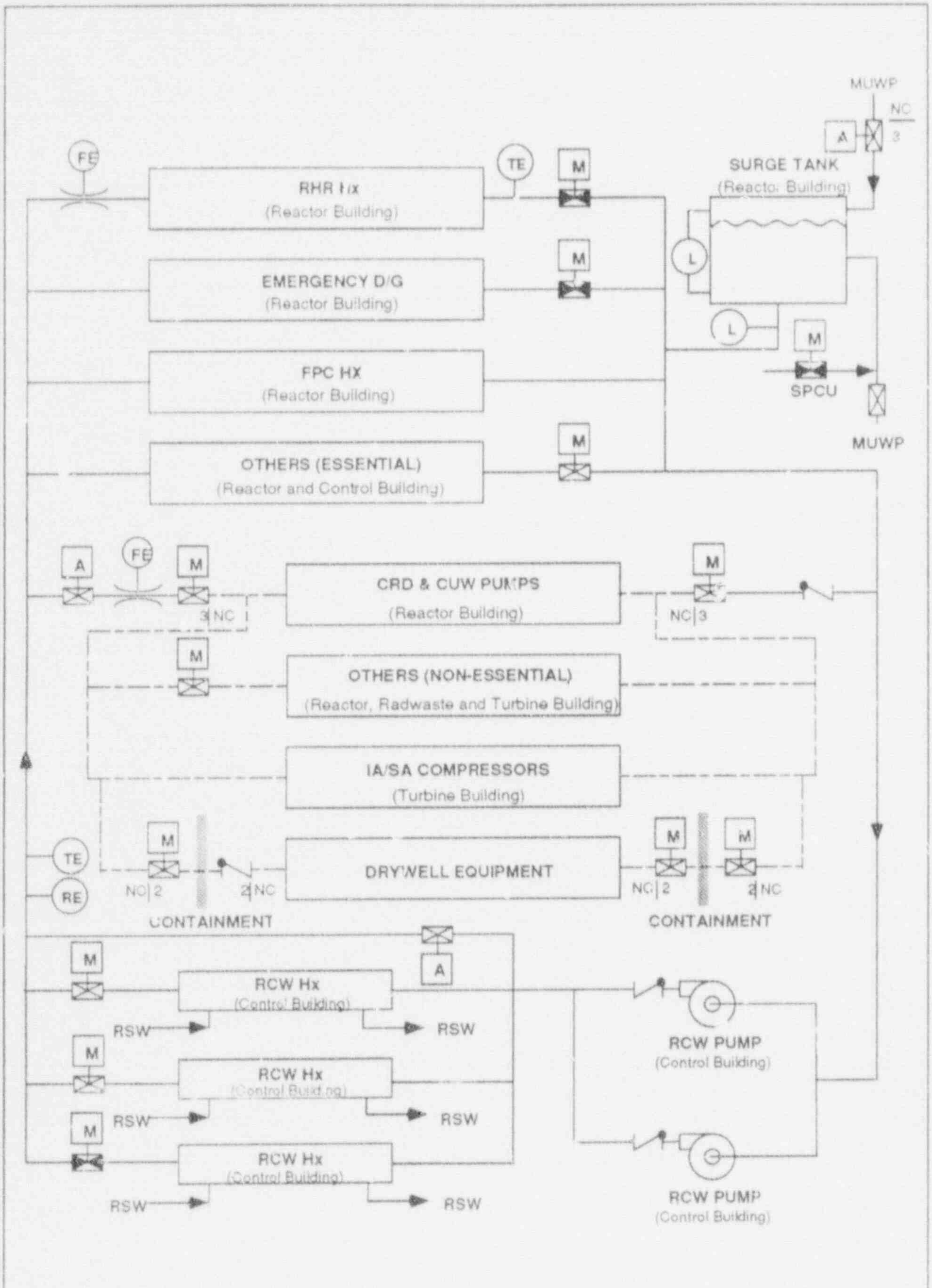


Figure 2.11.3a RBCW Division - A

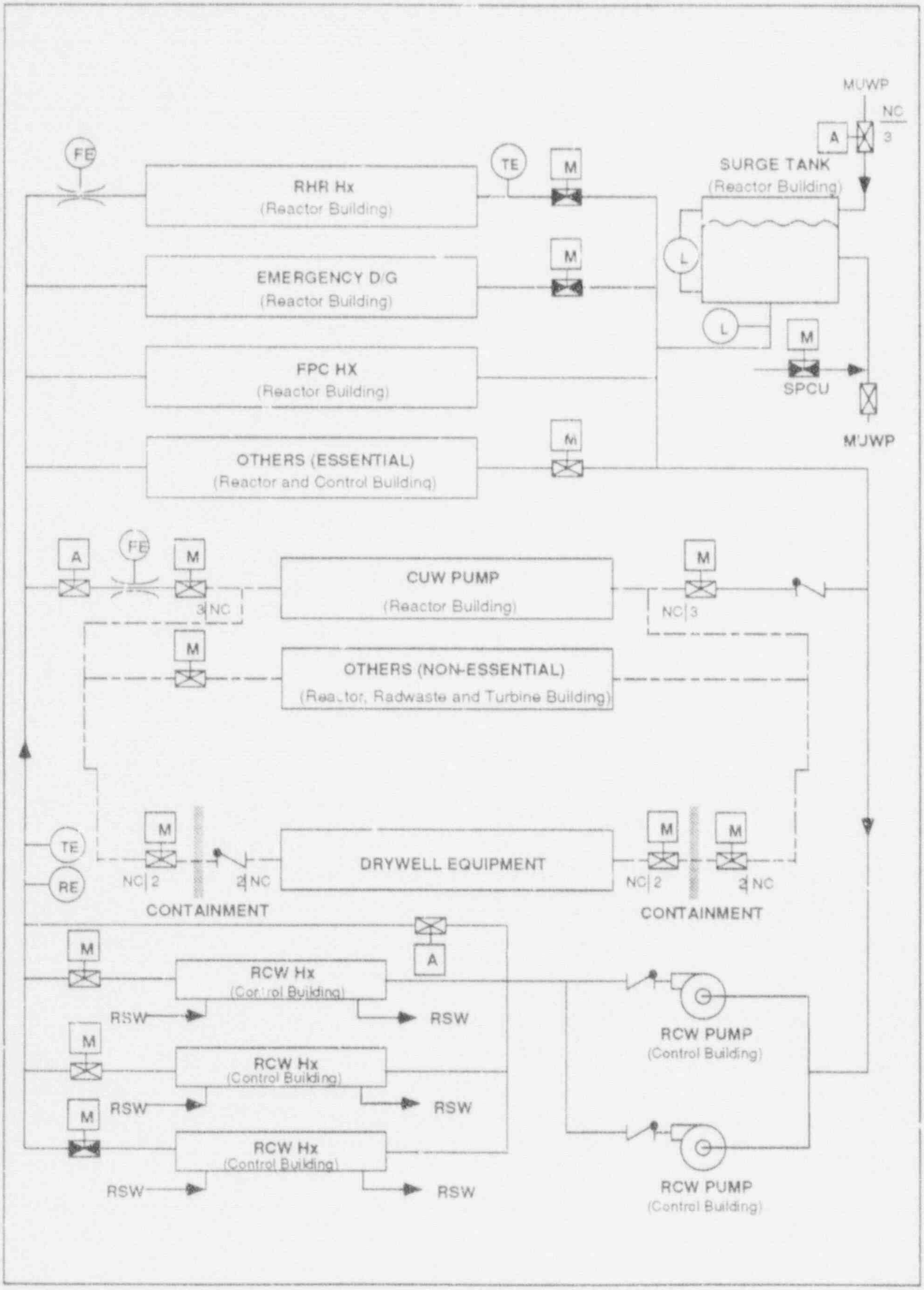


Figure 2.11.3b RBCW Division - B

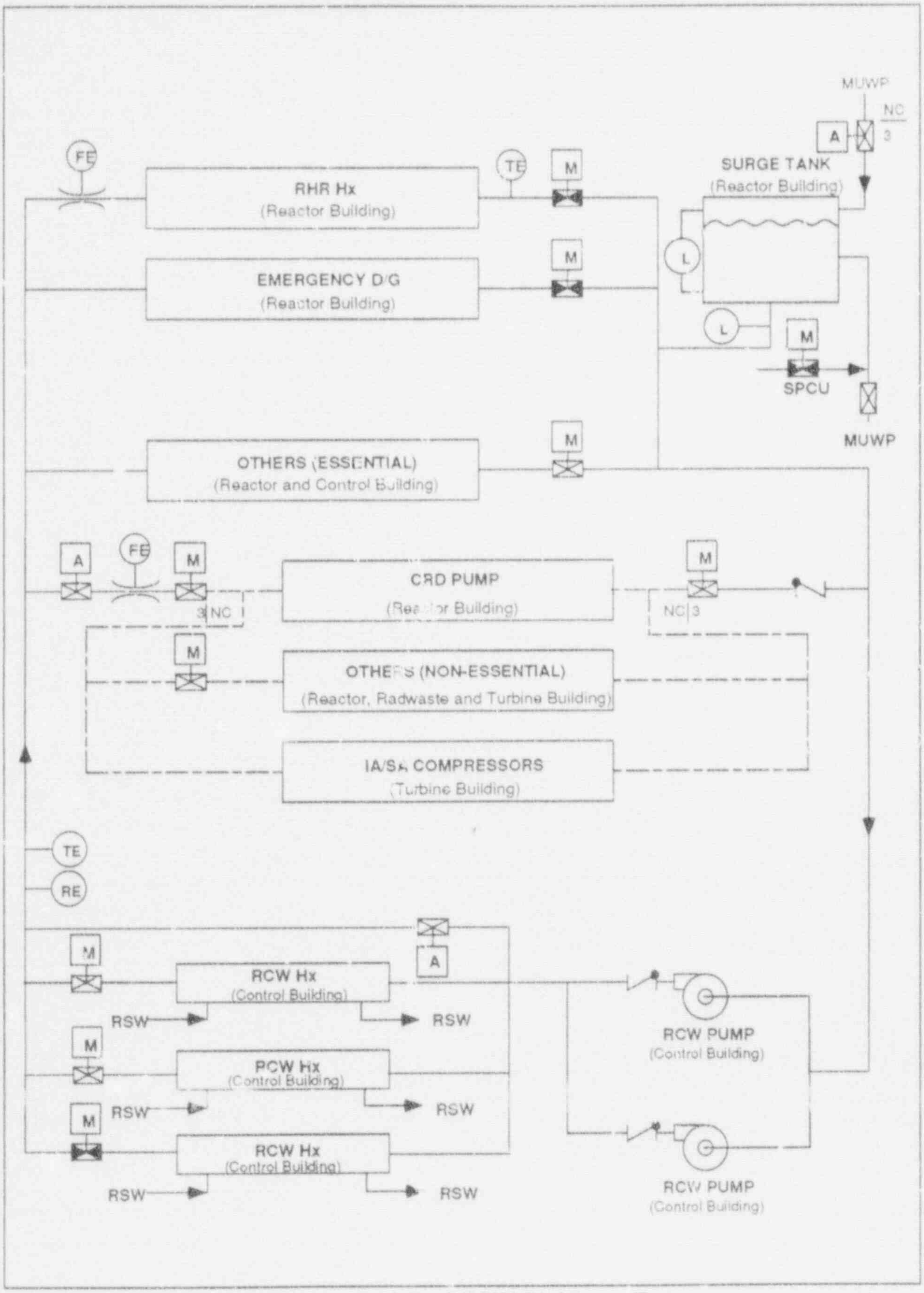


Figure 2.11.3c RBCW Division - C

2.11.4 Turbine Building Cooling Water System

Design Description

The Turbine Building Cooling Water (TCW) System provides corrosion-inhibited demineralized cooling water to the turbine island auxiliary equipment.

The TCW System consists of one surge tank, one chemical addition tank, three parallel pumps each of 50 percent capacity, three parallel heat exchangers each of 50 percent capacity, associated coolers, piping, valves, controls, and instrumentation. The TCW System rejects heat into the Turbine Service Water (TSW) System. The surge tank provides makeup water for continuous system operation. The makeup water flow to the surge tank is initiated automatically by low surge tank water level and continues until normal water level is established. During normal plant operation, two of the three 50 percent capacity pumps circulate water through the shell side of two of the three 50 percent heat exchangers in service. The standby TCW pump is automatically started on detection of low TCS System pump discharge pressure. The standby TCS System heat exchanger when required, is placed in service manually. The system configuration is shown in Figure 2.11.4.

Surge tank high and low levels, and TCW pump discharge pressure are alarmed in the TCW local panel as well as in the main control room.

The TCW system is classified as a non-safety-related, non-seismic system.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.4 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the TCW system.

Table 2.11.4: Turbine Building Cooling Water System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Test, Analysis	Acceptance Criteria
1. The configuration of the TCS System is shown in Figure 2.11.4.	1. Inspection of the as-built TCW System configuration shall be performed.	1. As-built TCW System configuration for those components shown, conforms with Figure 2.11.4.

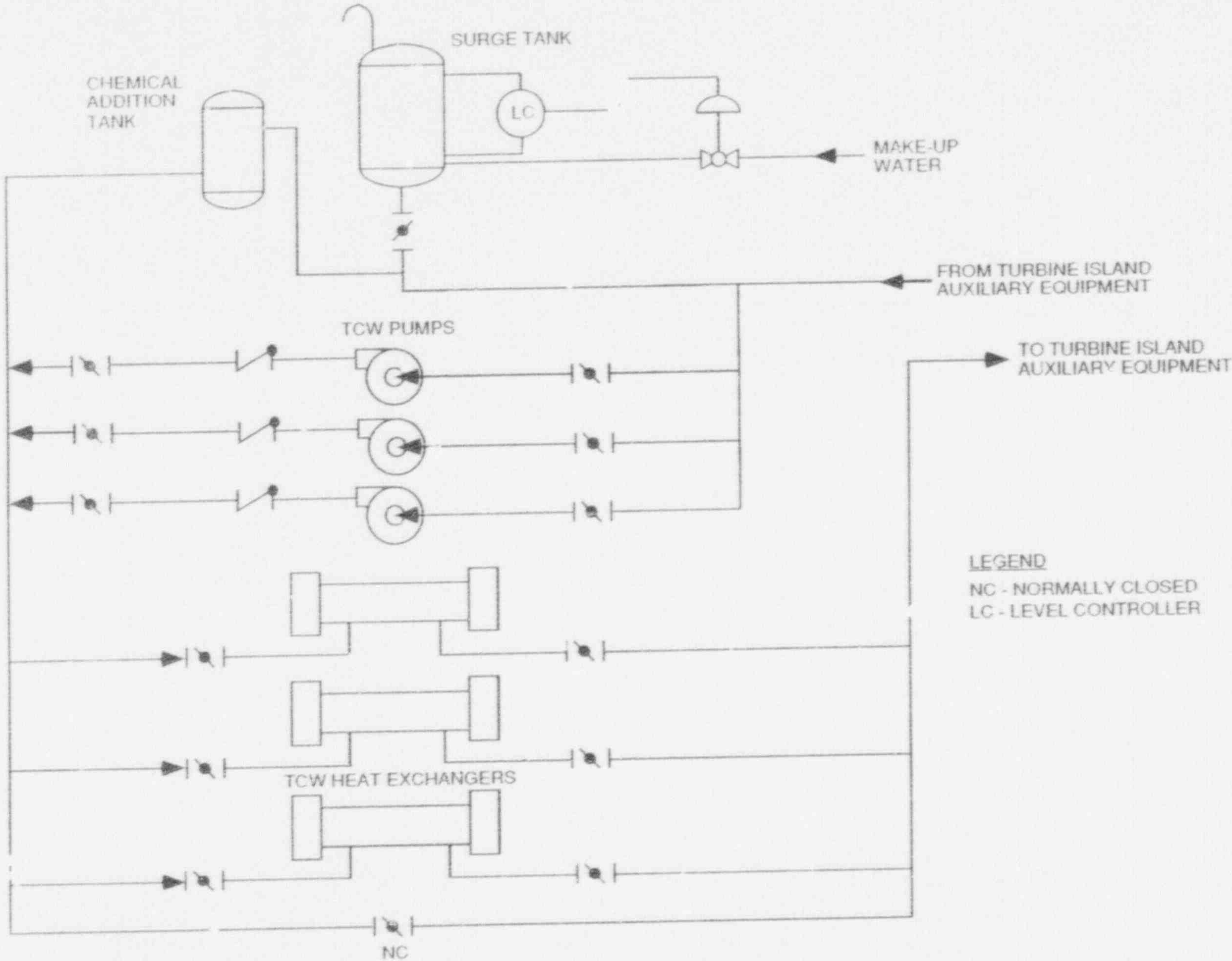


Figure 2.11.4 Turbine Building Cooling Water (TCW) System

2.11.5 HVAC Normal Cooling Water System

Design Description

The HVAC normal cooling water system (HNCW) delivers chilled water to the cooling coils of the drywell coolers, each building supply unit and the local air conditioners to maintain design thermal environments during normal and upset plant conditions.

The HNCW system consists of five 25% chillers, each with pumps, serving a common chilled water distribution system connected to the chilled water cooling coils in the drywell coolers, each building supply unit and the local air conditioners. Condenser cooling is provided by the turbine building cooling water system. The chiller and pump sets have a three-way mixing valve or a flow control valve to maintain the desired temperature. The system uses makeup water from a surge tank which is shared between the HNCW, turbine cooling water and hot water heating systems.

The HNCW system is not safety-related. However, the portions of the HNCW system which penetrate the primary containment are provided with isolation valves and penetrations which are designed to Seismic Category I, ASME code, Section III, Safety Class 2, Quality Group B requirements. The isolation valves may be manually operated from the control room except when a LOCA signal is present.

Each chiller and pump unit is designed to meet the following requirements:

Chiller Capacity Each (BTU/h) 8.9[illegible]6

The HNCW system is capable of removing the maximum heat loading during annual shutdown with one of the five pump and chiller units in standby. In case of a chiller or pump trip, the standby unit is automatically started. Flow switches also prohibit any chiller from operating unless there is water flow through the evaporator and condenser.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.5 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the HNCW system.

Table 2.11.5: HVAC Normal Cooling Water (HNCW) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The standby chiller and pump unit automatically starts when an operating chiller or pump trips.	1 Tests simulating chiller and pump failures will be conducted for each chiller and pump unit.	1. Each chiller and pump unit acting as a standby unit successfully starts upon a trip signal from any one of the operating units.
2. The HNCW cooling capacity is capable of removing the design heat loads.	2. Inspections of vendor documentation will include chiller and pump capacities. Flow tests will confirm that adequate flow is available to the system	2. Each chiller unit shall have an effective heat removal capacity of 8.93E6 BTU/h.
3. Isolation valves on the supply and return lines through the primary containment shall close on a LOCA signal. Isolation valves may be manually operated from the control room.	3. Tests simulating a LOCA signal shall be conducted on the HNCW system logic. All isolation valves in the HNCW system shall be opened and closed from the main control room switches.	3. Visual inspections shall confirm that the isolation valves close upon a LOCA signal. Visual inspections shall confirm that the isolation valves open and close from the main control room switches.

2.11.6 HVAC Emergency Cooling Water System

Design Description

The HVAC Emergency Cooling Water (HECW) System delivers chilled water to the control building essential electrical equipment room coolers, the diesel generator zone coolers, and the main control room coolers during shutdown of the reactor, normal operating modes, and abnormal reactor conditions including LOCA.

The HECW System consists of three mechanically separated divisions (Figure 2.11.6). Each division provides cooling to one control building e[illegible] electrical equipment room and one diesel generator zone. Eit[illegible] "C" also provides cooling to the main con[illegible]ol room. Pow[illegible] division from independant Class 1E sources.

HECW division "A" consists of one pump, one refrigeration [illegible] instrumentation, and distribution piping and valves to the cooling coils. Divisions "B" and "C" are similar except that two parallel pumps and refrigeration units are used. Surge tanks and condenser coolant flow are provided by the corresponding division of the RCW System. A chemical addition tank is shared by all HECW divisions.

Makeup water is supplied from the makeup water (Purified) system at the surge tanks. The surge tanks are capable of replacing system water losses for more than 100 days during an emergency.

The refrigeration and pump units are designed to meet the following requirements:

(1)	Refrigerator Capacity (BTU/hr)	2.3×10^6
(2)	Pump Capacity (gpm)	256

All major system components are located in the control building except for the diesel generator zone cooling coils, which are in the reactor building. There are no primary or secondary containment penetrations within the system. In addition, the system layout is designed to permit periodic in-service inspection of all system components to assure the integrity and capability of the system.

Piping and valves for the HECW System, as well as the cooling water lines from the RCW System, are designed to Seismic Category I and ASME Code, Section III, Class 3 and Quality Group C requirements. The classification extends up to and including the block valves for the chemical addition tank. The only non-safety-related portion of the system is the chemical addition tank and the piping from the tank to the block valves.

The HECW System is capable of removing all heat loads with one of the four pump and refrigerator units from division "B" and "C" in standby. The standby refrigerator is equipped with an interlock which automatically starts the unit upon failure of the operating refrigerator. Flow switches prohibit the refrigerators from operating unless there is water flow through the evaporator and condenser. The refrigerator units can be controlled individually from the main control room by a remote manual switch.

The HECW System is designed to perform its required safe reactor shutdown cooling function following a postulated loss-of-coolant accident/loss of offsite power (LOCA/LOOP), assuming a single active failure in any mechanical or electrical division. In case of a failure which disables any one of the three HECW divisions, the other two divisions meet plant safe shutdown requirements.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.6 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the HECW System.

Table 2.11.6: HVAC Emergency Cooling Water (HECW) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The system configuration includes key components and flow paths as shown in Figure 2.11.6.	1 Inspection of construction records will be performed. Visual inspection (VI) will be performed based on Figure 2.11.6.	1. The system configuration conforms with Figure 2.11.6.
2. The HECW divisions are mechanically and electrically independent. The HECW divisions are powered by independent Class 1E sources.	2. Tests and VI of the divisions will include independent and coincident operation of the three divisions to demonstrate complete divisional separation. VI will check for independent Class 1E power sources.	2. Plant tests and VI confirm proper independence of each HECW division. VI confirm Class 1E power sources for each HECW division.
3. The standby refrigerator and pump units automatically start upon high temperature cooling water or failure of the operating units. The refrigerator units can be controlled individually from the main control room.	3. Tests simulating high temperature cooling water and operating pump failure will be conducted for each refrigerator and pump unit in divisions "B" and "C". Tests simulating main control room switch signals will be conducted for the refrigerator units.	3. Refrigerator and pump units acting as standby units start upon a high temperature cooling water or operating pump failure signal. Refrigerator and pump units are operable from main control room signals.
4. The HECW cooling capacity is capable of removing the heat loads on the system.	4. Inspections of vendor documentation will include refrigeration and pump capacities. Flow tests will confirm that adequate flow is available to the system.	4. Each refrigeration unit shall have an effective heat removal capacity of 2.3×10^6 Btu/hr at 256gpm. Each pump is capable of delivering 256 gpm to the system.

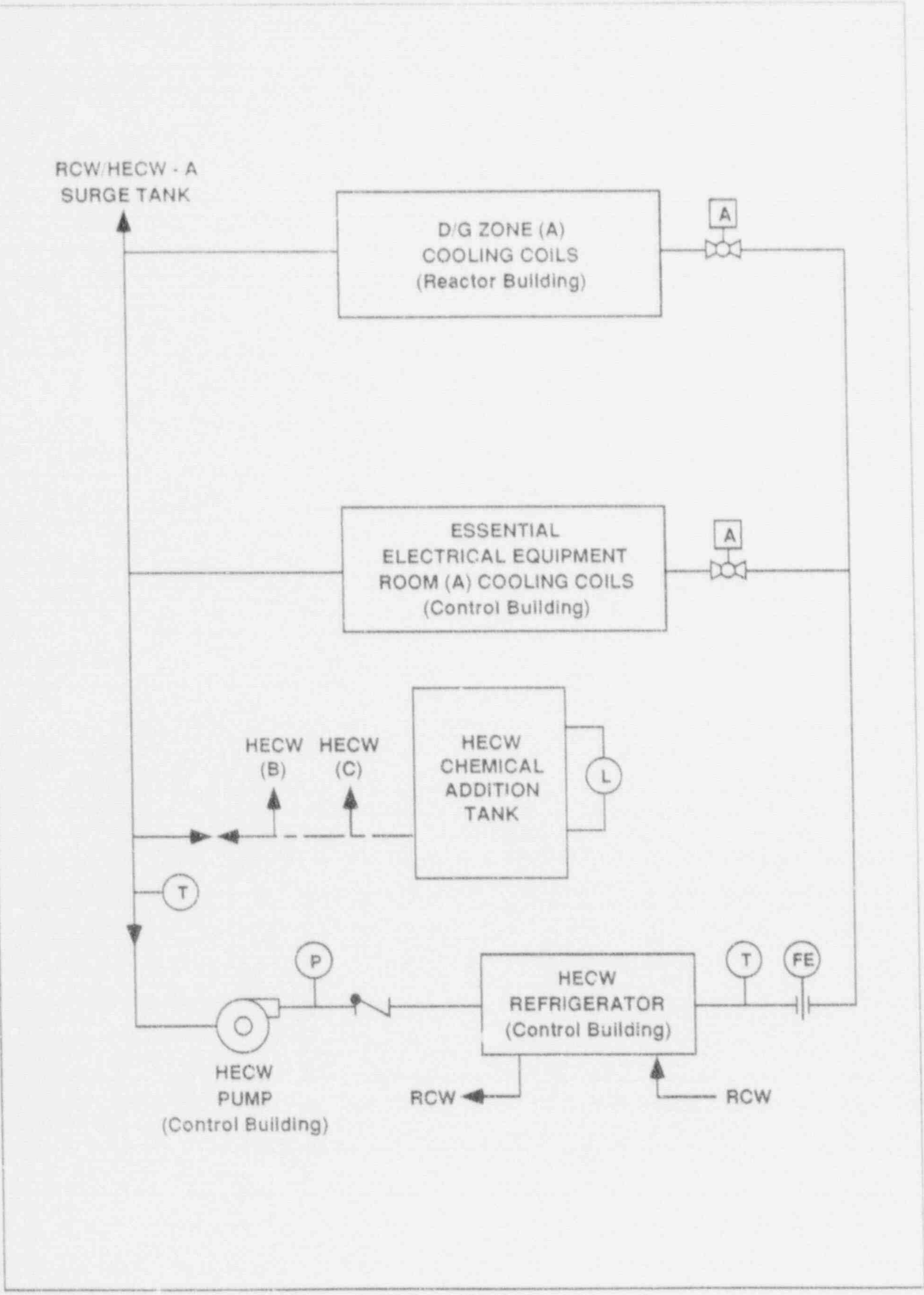


Figure 2.11.6a HECW Division - A

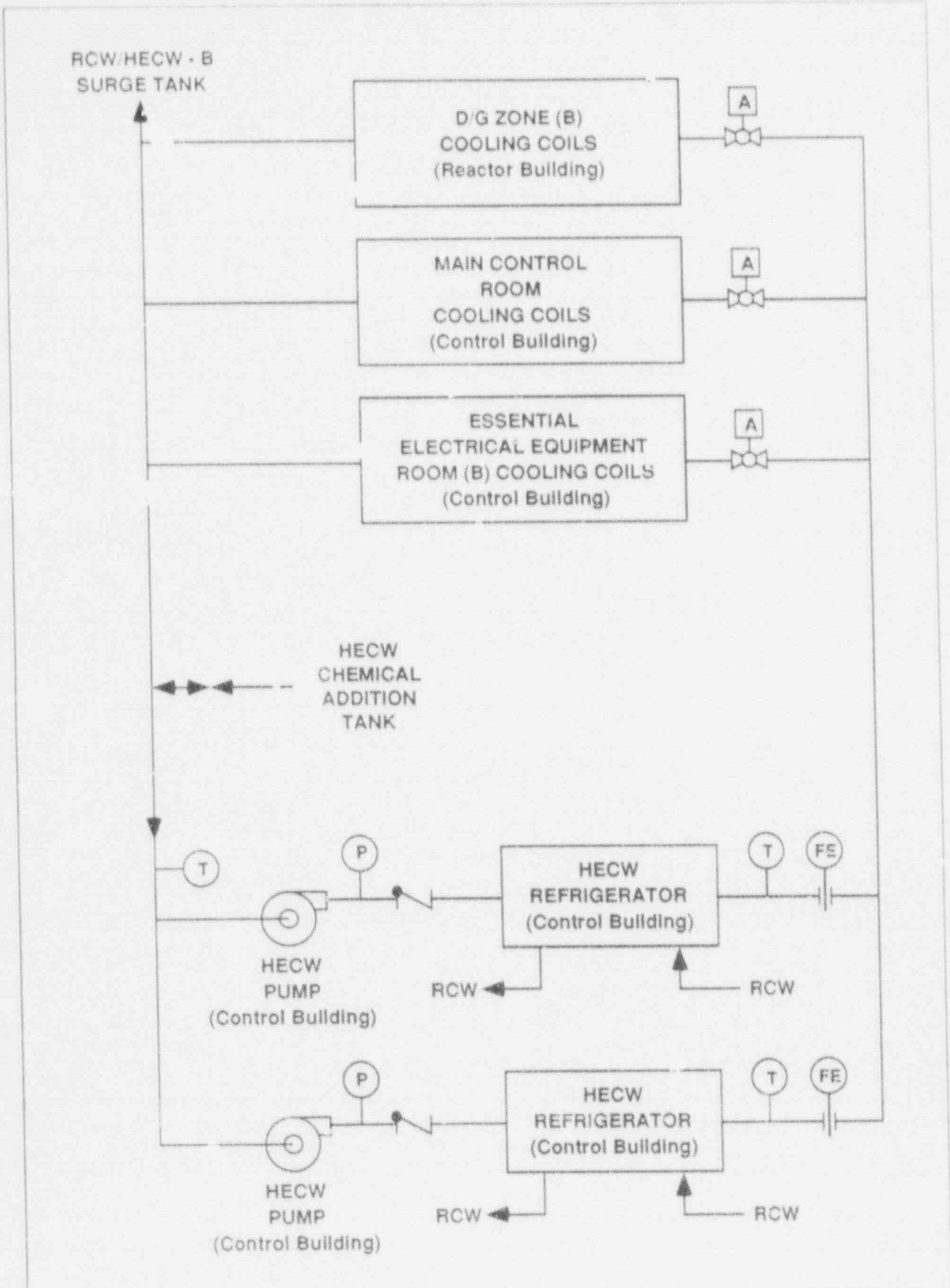


Figure 2.11.6b HECW Division - B

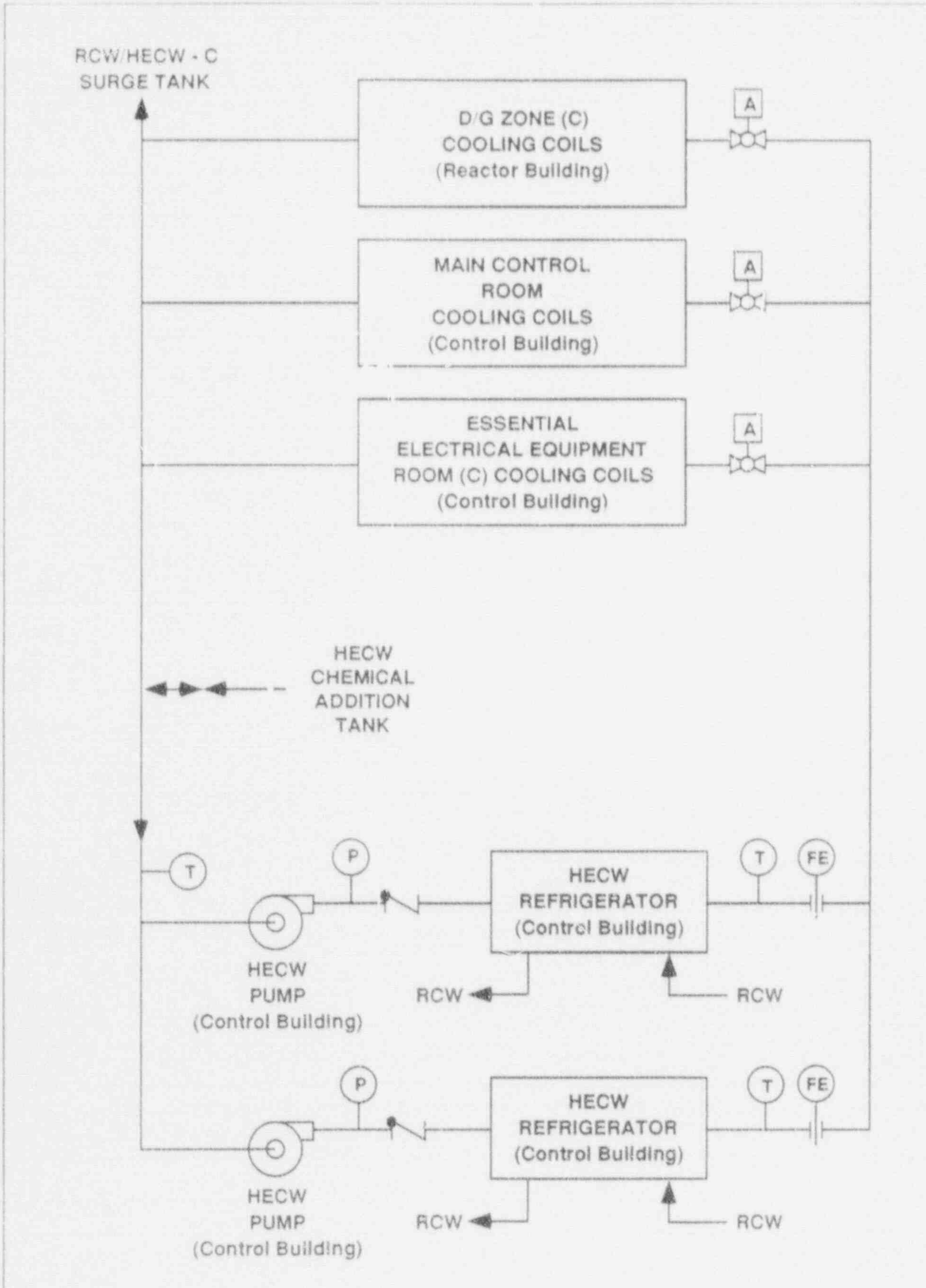


Figure 2.11.6c HECW Division - C

2.11.7 Oxygen Injection System

No Tier 1 entry for this system.

2.11.8 Ultimate Heat Sink

Interface item. Covered by Item 4.1.

2.11.9 Reactor Service Water System

Design Description

The function of the Reactor Service Water (RSW) System is to remove heat from the Reactor Building Cooling Water (RCW) System and reject this heat to the Ultimate Heat Sink (UHS).

The portions of the RSW System that are in the control building are within the ABWR scope and those portions of the RSW System that are outside of the control building are not in the ABWR scope and are described as interface requirements. The system is classified as safety related and has three separate divisions.

Design Description

Inside the control building, the service water piping enters divisionally separted areas and rooms and is sent to and from the RCW/RSW heat exchangers which are part of the RCW system.

The requirements in the last two paragraphs of this section also apply to the portion of the RSW system in the control building.

Interface Requirements

Outside the control building, the pumps, strainers, valves, instruments, and controls are located in the US pump house. Piping connects those portions of the RSW system in the UHS pump house and the control building.

The total heat removal capacity of the RCW, RSW, and UHS is sufficient to remove heat loads associated with emergency shutdown and post-LOCA core and containment cooling. The system also removes heat during normal plant operation and shutdown.

The RSW system is designed to perform its functions taking into consideratio site specific factors. These factors include adequate NPSH for the RSW pumps under all water level fluctuations in the UHS, tendency for organic or macrobial fouling and means for their control and component and piping materials compatible with the UHS water. Measures to prevent flooding in the control building after a pipline break will be included.

strainers, valves, their per supplies and controls in the UHS pump house which is a Seismic Category I structure and away from high energy piping systems.

If a loss of preferred power occurs, all RSW system pumps and heat exchangers will automatically be laced in service using diesel generator power.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.9 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria for the RSW system.

Table 2.11.9: Reactor Service Water System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Adequate pump NPSH is available for the RSW pumps under all anticipated water level conditions in the UHS.	1. Available NPSH and requirements will be determined by analysis and compared to the NPSH of the as-built pumps.	1. Adequate NPSH is available under all anticipated conditions.
2. Provisions will be made to prevent organic and macrobial fouling.	2. Analyses of potential fouling problems in the UHS water source shall be performed and compared to the as-built provisions to prevent fouling.	2. Design provisions are in place to preclude unacceptable fouling or degradation of the RSW System performance.
3. Proper materials for RSW components and piping will be selected.	3. Analyses of potential corrosion problems in the UHS water source shall be performed and compared to the capabilities of the as-built equipment.	3. The design has appropriate anti-corrosion features.
4. Provisions will be made to prevent control building flooding if a pipeline break occurs in or near the control building.	4. An analysis will be performed of a pipe break in the control building using conservative assumptions. The extent of flooding will be estimated based on as-built component characteristics and site-specific UHS.	4. The control building flooding shall not affect any other RCW division or any other safety related equipment or areas.
5. RSW System can remove the heat from RCW System following a LOCA.	5. The heat removal capacity of the RSW divisions will be compared with the heat removal requirements of the RCW System divisions by evaluation of the as-built components.	5. The heat removal capacity of the RSW divisions is adequate to remove the heat from the divisions of the RCW System.
6. The RSW divisions are separated mechanically and electrically and are protected from the events listed in the Design Description.	6. Inspections and analyses will be performed of the mechanical and electrical separation and the measures to protect the RSW components and piping.	6. The RSW divisions are separated mechanically and electrically and are protected against events listed in the Design Description.

2.11.10 Turbine Service Water System

Design Description

The Turbine Service Water (TSW) System provides cooling water to the Turbine Building Cooling Water (TCW) System heat exchangers to transfer heat from the TCW System to the power cycle heat sink during normal and shutdown conditions. During normal operation the TSW System supplies cooling water to the TCW System heat exchangers at a temperature not exceeding 38 degrees C.

The portion of the TSW System located inside the turbine building is within the scope of certified design, and the portion of the TSW System located outside the turbine building is not within the scope of certified design.

The portion of the TSW System that is within the scope of certified design consists of TSW water supply and discharge lines and manual isolation valves supplying cooling water to the TCW system heat exchangers. The portion of the TSW System not within the scope of certified design has redundant pumping capacity and supplies sufficient water flow to the portion within the scope of certified design.

The system configuration of the portion within the scope of certified design is shown in Figure 2.11.10.

The TSW System is classified as a non-safety-related, non-seismic system.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.10 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the TSW System.

Table 2.11.10: Turbine Service Water System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the TSW System is shown in Figure 2.11.10.	1. Inspection of the as-built TSW System configuration within the scope of certified design shall be performed.	1. As-built TSW System configuration for those components within the scope of certified design, conforms with Figure 2.11.10.
2. The TSW System certified design portion receives sufficient flow with redundant pump capacity.	2. Inspection of the TSW System portion not within the scope of certified design.	2. The TSW System portion not within the scope of certified design supplies sufficient water flow and has redundant pumping capacity.

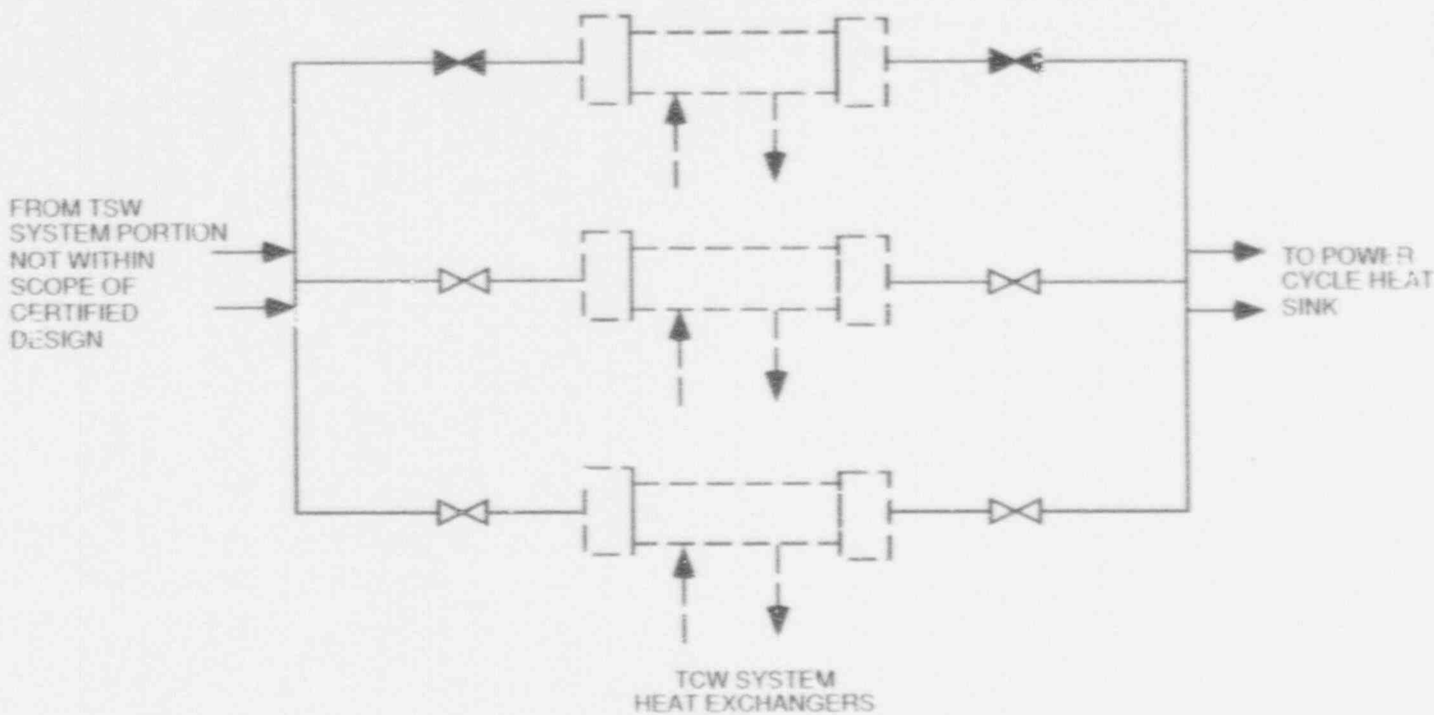


Figure 2.11.10 Turbine Service Water System (Portion Within Scope of Certified Design)

2.11.11 Station Service Air System

Design Description

The Station Service Air (SA) System is designed to provide a continuous supply of compressed air of suitable quality for general plant use. Service air is primarily used for tank sparging, filter/demineralizers backwashing, air operated tools, and other services requiring air quality lower than that of the Instrument Air System. Another SA System function is to provide pneumatic backup to the IA System in the event IA system pressure is lost.

The SA System consists of two air compressing trains, an air receiver tank, two trains of dryer/filters, distribution piping, valves, control and instrumentation.

Each of the two air compressors is sized to provide 50% of the peak air consumption. One of the two compressors is normally operating while the other is on standby. The standby compressor automatically starts when the pressure in the receiver tank drops below the low pressure setting and automatically stops when the normal operating pressure has recovered.

The SA System has no safety related function except the containment penetration which is required to maintain containment integrity. The containment penetration portion is designed to Seismic Category I, Quality Group B. It consists of a check valve inside containment and a manually operated valve on the outside. This manual valve is locked closed during normal plant operation and is opened only during refueling to admit service air inside the containment. The SA distribution piping system is non-seismic, and is designed to Quality Group D.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.11 provides definition of inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for SA system.

Table 2.11.11. Station Service Air System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the SA system is as shown in Figure 2.11.11.	1. Inspection of the as-built SA system configuration shall be performed.	1. Verification of the as-built system is in conformance with the as-designed configuration (Figure 2.11.11).
2. The SA system outboard isolation valve can be manually closed.	2. Actual testing shall be performed to demonstrate that the outboard isolation valve can be manually closed.	2. Manual closure of the outboard isolation valve.

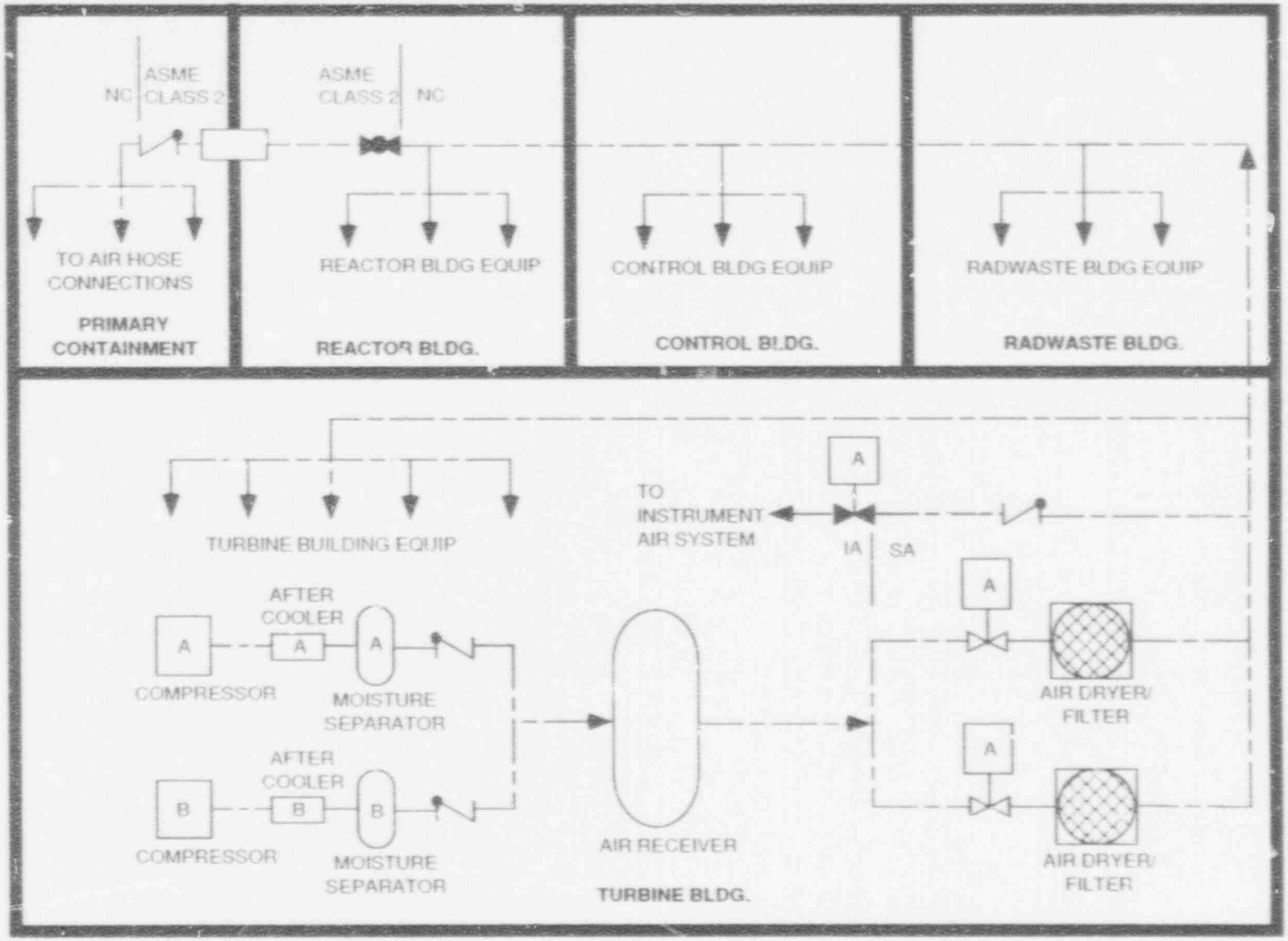


Figure 2.11.11 Station Service Air System

2.11.12 Instrument Air System

Design Description

The Instrument Air (IA) System is designed to provide a continuous supply of clean, dry and oil free compressed air for pneumatic equipment, valves, controls and instrumentation outside the primary containment.

Portion of the IA System distribution piping penetrates the containment but is normally isolated from the IA supply by a normally closed air operated valve. Pneumatic supply to this line is normally supplied by the High Pressure Nitrogen Gas Supply (HPIN) System which supplies the nitrogen gas for the containment atmosphere so the containment is normally inert. In the event HPIN pressure is lost, IA System provides air backup to the equipment that requires nitrogen inside containment by remote manual alignment of the associated valves to the IA System. During refueling, IA also provides air supply to equipment that requires inside containment through this line.

The IA System consists of two air compressing trains, an air receiver tank, two drying trains in parallel, distribution piping, valves, control and instrumentation. Each compressing train consists of suction filter, 100% oil free air compressor, after cooler and moisture separator. One of the two compressors is normally operating while the other is on standby. The standby compressor automatically starts when the pressure in the receiver tank drops below the low pressure setting and automatically stops when the normal operating pressure has recovered. In the event of an unusual drop of air receiver pressure, the SA System provides air supply backup to the instrument air users.

The IA System has no safety related function except the containment penetration which is required to maintain containment integrity. The containment penetration portion is designed to Seismic Category I, Quality Group B. It consists of a check valve inside containment and a motor operated valve on the outside. The IA distribution piping system is non-seismic, and is designed to Quality Group D.

The IA System is connected to emergency power for continued operation during a loss of off-site power event.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.12 provides definition of inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for IA system.

Table 2.11.12: Instrument Air System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the IA System is shown in Figure 2.11.12.	1. Inspection of the as-built IA System configuration shall be performed.	1. Verification of the as-built conformance with the as-designed configuration (Figure 2.11.12).
2. The IA System outboard isolation valve closes upon receipt of auto isolation signal from the Leak Detection System.	2. Functional testing shall be performed on the system logic by simulating the auto isolation signal from the Leak Detection and Isolation System.	2. Valve isolates upon receipt of auto isolation signal.
3. The IA System capability to operate on on-site emergency AC power source.	3. IA System functional testing shall be performed to demonstrate operation when supplied from on-site emergency AC power sources.	4. Satisfactory IA System operation with power supplied from on-site emergency AC power sources

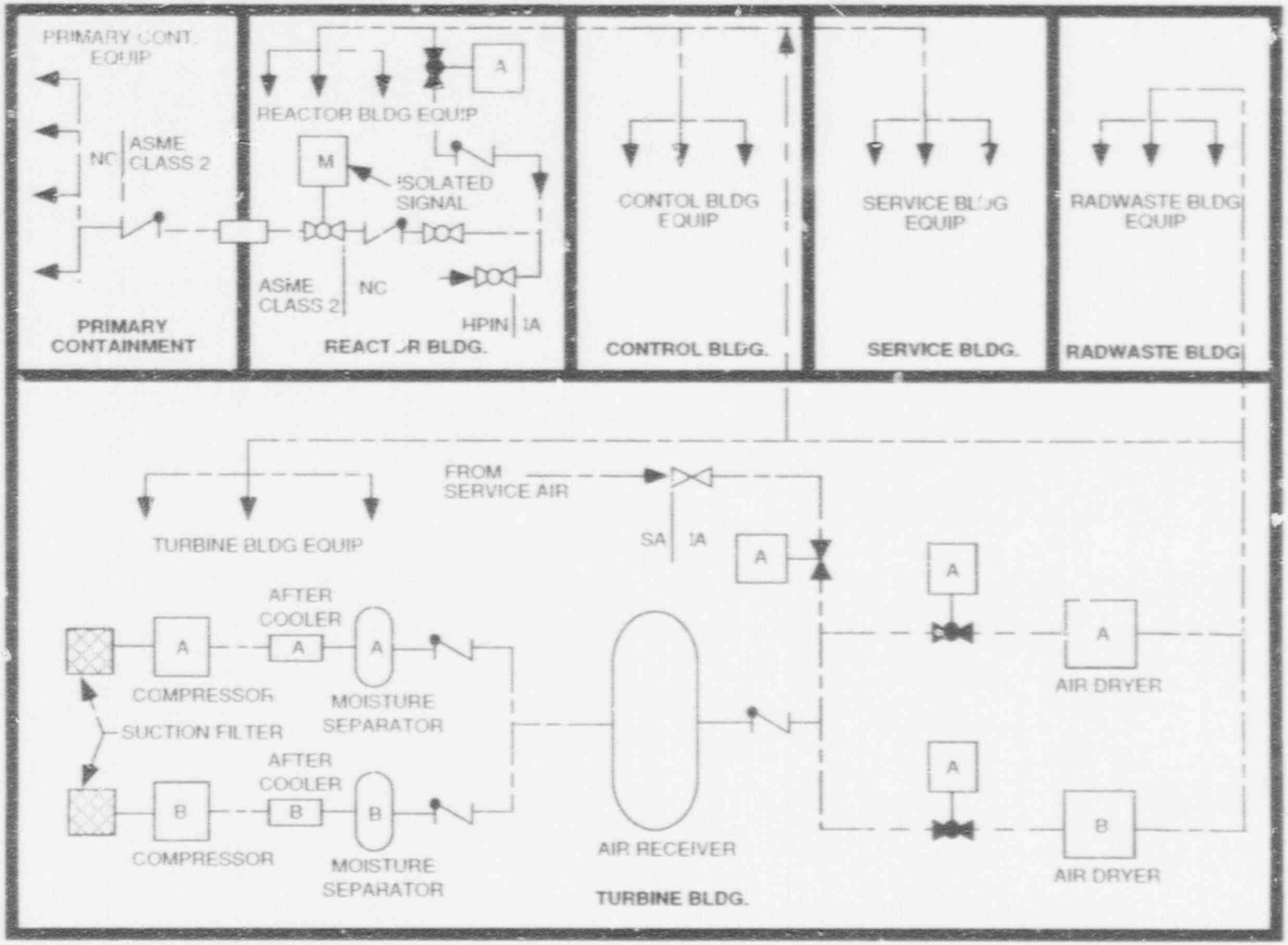


Figure 2.11.12 Instrument Air System

2.11.13 High Pressu e Nitrogen Gas Supply System

Design Descriptic n

The High Pressure Nitrogen Gas Supply (HPIN) System is designed to provide nitrogen gas to pneumatic equipment inside primary containment. The HPIN System consists of two independent subsystems one being safety-related and the other non-safety-related. The non-safety-related portion receives its nitrogen gas source from the Atmospheric Control (AC) System and distributes it inside containment for the following equipment:

(1) relief function accumulators of main steam safety/relief valves.

(2) nitrogen operated valves and instruments inside containment.

(3) leak detection system radiation monitor calibration.

(4) Automatic Depressurization System (ADS) function accumulators of the main steam safety/relief valves to compensate leakage durin normal operation.

Following a LOCA, nitrogen supply to the ADS function accumulators are supplied by the safety-related HPIN subsystem. The safety-related subsystem consists of two redundant divisions supplied from high pressure nitrogen gas storage bottles. Each division is mechanically and electrically separated from the other. One division supplies nitrogen to half of the ADS designated safety/relief valves and the other division for the remaining half. The nitrogen storage bottles supply valve is normally closed with key lock control switch normally in "auto" mode. Remote manual closure and opening can only be accomplished with the key. The supply valve automatically opens in response to low pressure condition in the ADS accumulator supply line. During this emergency mode of operation, power to the safety-related HPIN subsystem is automatically switched to divisional emergency AC power sources.

Separations between the safety-related and the non-safety-related portions of the HPIN System are provided by motor operated shutoff valves that automatically close on low pressure condition in the ADS and non-ADS SRV accumulator supply lines.

The non-safety-related portion is designed to non-seismic class, Quality Group D, while the safety-related portion is Safety Class 3, Seismic Category I, Quality Group C, Electrical Class 1E. The shutoff valves separating safety-related from the non-safety-related portions are Seismic Category I, Quality Group C design. All primary containment penetrations meet Seismic Category I, Quality Group C design requirements.

From the nitrogen gas bottles up to the pressure reducing valve is designed to 200 kg/cm^{2}g (2845 psig). This is true for both divisions of the HPIN safety-related subsystem. The remainder of the HPIN System including safety-related and non-safety-related portions is rated at 18 kg/cm^{2}g (250 psig).

The HPIN System is provided with instrumentation and controls to monitor the system design basis operation. These include high and low pressure alarms, indications, valve position status lights, and others.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.13 provides definition of inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the HPIN System.

Table 2.11.13: Remote Shutdown System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the HPIN System is shown in Figure 2.11.13.	1. Inspection of the as-built HPIN System configuration shall be performed.	1. Verification of the as-built conformance with the as-designed configuration (Figure 2.11.13).
2. The nitrogen gas bottles supply valve automatically opens on low pressure and automatically closes on high pressure conditions at the ADS accumulator supply line.	2. Using simulated high and low pressure signals, functional testing of the system logic shall be performed to demonstrate automatic opening and closing capability of the nitrogen gas bottles supply valve with the control switch in "auto" mode.	2. Automatic opening and closing of the nitrogen gas bottles supply valve.
3. The nitrogen gas bottles supply valve remote manual operability.	3. Demonstrate remote manual actuation of the nitrogen gas bottles supply valve from the main control room with key.	3. Remote manual open/close actuation from the main control room with key. No valve actuation when key is not used.
4. The safety-to-non-safety related interface shutoff valves automatically close on low pressure condition on the ADS and non-ADS accumulator supply lines.	4 Functional testing utilizing simulated signals shall be performed to demonstrate auto closure of the safety-to-non-safety interface shutoff valves on low pressure condition at the ADS and non-ADS accumulator supply lines.	4. Auto closure of the safety-to-non-safety interface shutoff valves.
5. The safety-related portion of HPIN System automatically switches power to emergency AC on loss of normal power supply.	5. Demonstrate automatic power switching and HPIN System operability when supplied from the emergency AC sources.	5. HPIN System power switching and HPIN Systems operability on emergency AC sources.
6. HPIN outboard containment isolation valves remote manual closure capability.	6. Demonstrate remote manual closure capability of the HPIN outboard containment isolation valves from the main control room.	6. Valves remote manual closure from the main control room.
7. Provision for control room alarms, and indications vital for HPIN operation.	7. Inspection shall be performed to verify presence of control room alarms and indications.	7. The control room alarms and indications specified in Section 2.11.13.

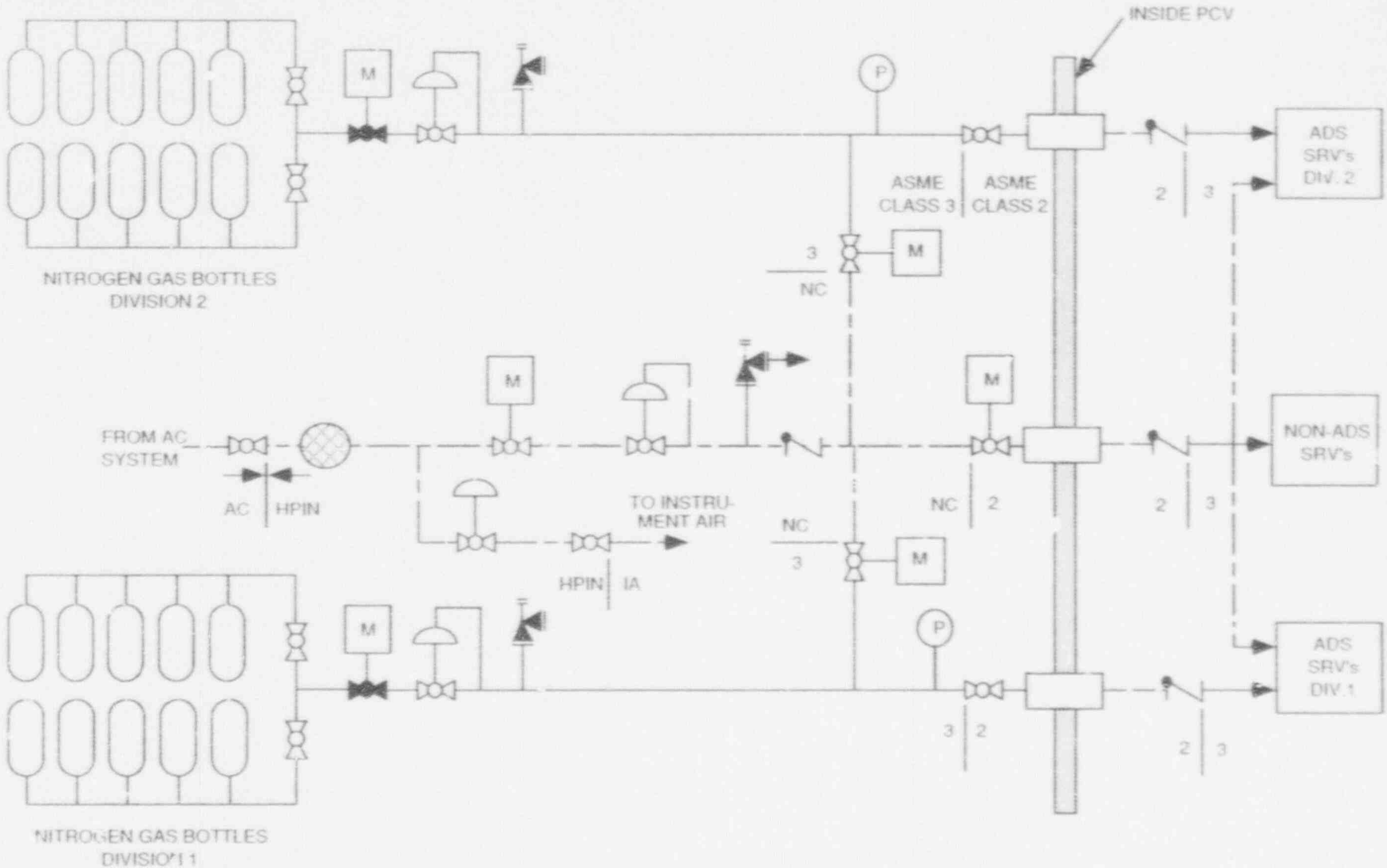


Figure 2.11.12 High Pressure Nitrogen Gas Supply System

2.11.14 Heating Steam and Condensate Water Return System

Design Description

The Heating Steam and Condensate Water Return (HSCR) System supplies heating steam from the house boiler for general plant use and recovers condensate to the boiler feedwater tanks. The system consists of piping, valves and associated controls and instrumentation.

The HSCR system is classified as a non-safety-related, non-seismic system.

Inspections, Tests, Analyses and Acceptance Criteria

No Tier 1 ITAAC for this system.

2.11.15 House Boiler

Design Description

The House Boiler (HB) System consists of the house boilers, reboilers, feedwater components, boiler water treatment and control devices. The HB System supplies turbine gland steam and heating steam.

The HB System is classified as a non-safety-related, non-seismic system.

Inspections, Tests, Analyses and Acceptance Criteria

No Tier 1 ITAAC for this system.

2.11.16 Hot Water Heating System

Design Description

The Hot Water Heating (HWH) System is a closed loop hot water supply to the various heating coils of the HVAC Systems. The HWH System includes two heat exchangers, a backup heat exchanger, surge and chemical addition tanks, and associated equipment, control and instrumentation.

The HWH System is classified as a non-safety-related, non-seismic system.

Inspections, Tests, Analyses and Acceptance Criteria

No Tier 1 ITAAC for this system.

2.11.17 Hydrogen Water Chemistry System

Design Description

The hydrogen water chemistry (HWC) system is used, along with other measures, to reduce the likelihood of corrosion failures which would adversely affect plant availability. BWR reactor coolant is demineralized water, typically containing 100 to 200 parts per billion (ppb) dissolved oxygen from the radiolytic decomposition of water. The function of the HWC system is to reduce the dissolved oxygen in the reactor water to less than 20 ppb by the addition of hydrogen to the feedwater. This reduction has been demonstrated to be highly effective in the mitigation of the potential for intergranular stress corrosion cracking (IGSCC) of sensitized austenitic stainless steels.

The concentration of hydrogen and oxygen in the main steam line and eventually in the main condenser is altered in this process. This leaves an excess of hydrogen in the main condenser that would not have equivalent oxygen to combine with in the offgas system. To maintain the offgas system near its normal operating characteristics, the HWC provides a flow rate of oxygen equal to approximately one-half the hydrogen flow rate, injected into the offgas system upstream of the recombiner.

The HWC system is composed of hydrogen and oxygen supply systems, systems to inject hydrogen in the feedwater and oxygen in the offgas and subsystems to monitor the effectiveness of the HWC system. A number of automatic control features are provided in the system to minimize the need for operator attention and to improve performance. Such controls include automatic variation of injection flow rates with reactor power and automatic shutdown for several alarm conditions.

The hydrogen water chemistry system is non-nuclear and non-safety-related. It is required to be safe and reliable, consistent with the requirement of using hydrogen gas. The hydrogen piping in the turbine building is designed to Seismic Category I requirements.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.17 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the HWC system.

Table 2.11.17: Hydrogen Water Chemistry System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The simplified system configuration of the HWC system is shown in Figure 2.11.17.	1. Inspection of installation records together with plant walkdowns will be conducted to confirm that the installed equipment is in compliance with the design configuration defined in Figure 2.11.17.	1. The as-built HWC system configuration is in accordance with Figure 2.11.17.
2. The means of storing and handling hydrogen shall be safe and reliable, consistent with normal industry practices for prevention of hydrogen fires and explosions.	2. Perform a safety review of system operating procedures relating to the storage and handling of hydrogen and a safety inspection of all hydrogen processing equipment.	2. Reviews and inspections verify that the equipment and procedures for the storage and handling of hydrogen are safe and reliable.
3. The hydrogen piping in the turbine building shall be designed to Seismic Category I requirements.	3. Procurement records, design documents and actual equipment shall be inspected to verify that the requirements are met.	3. Records, documents and inspections verify that the hydrogen piping in the turbine building is designed to Seismic Category I requirements.

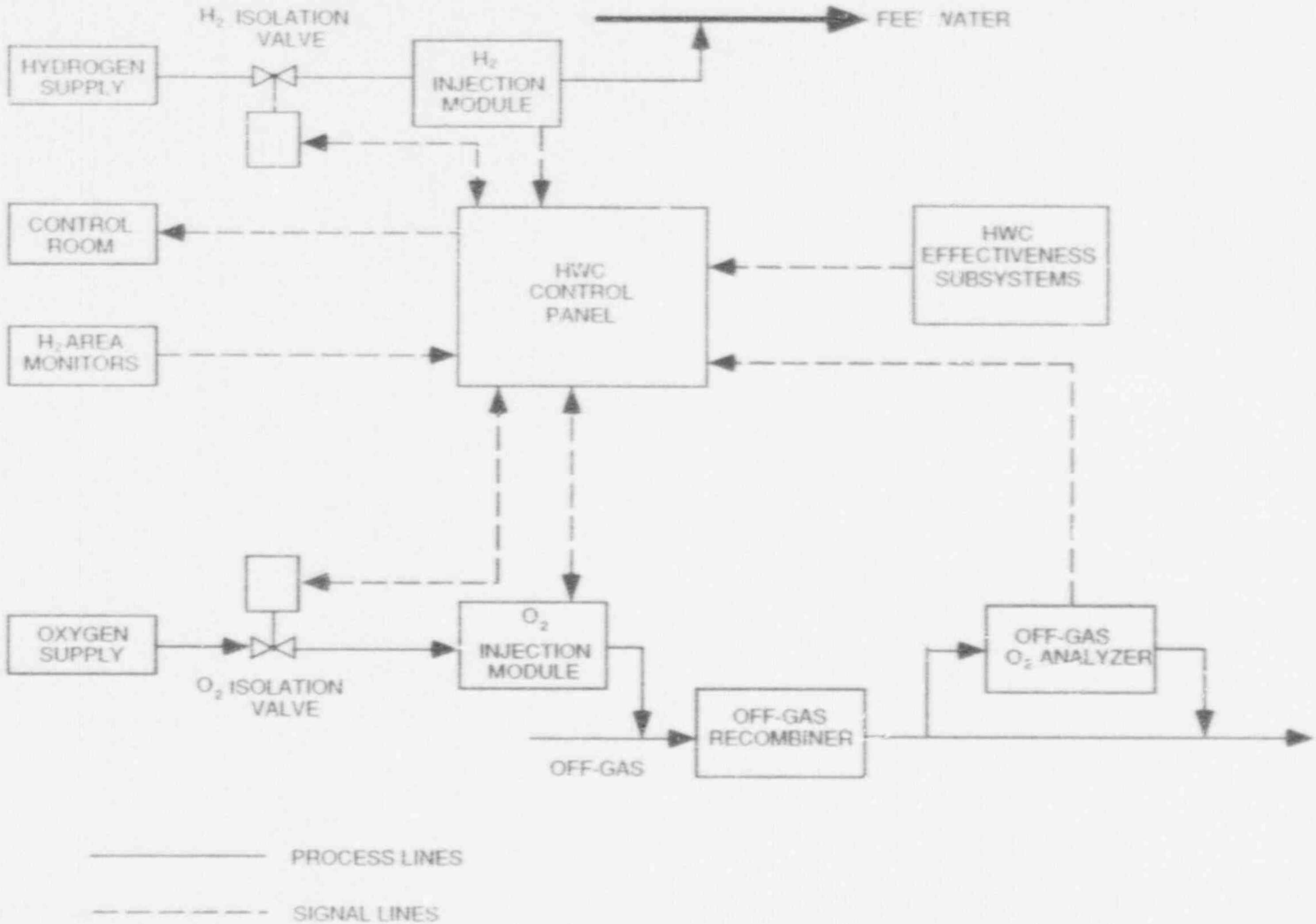


Figure 2.11.17 Hydrogen Water Chemistry System

2.11.18 Zinc Injection System

No Tier 1 entry for this system.

2.11.19 Breathing Air System

Design Description

The breathing air system provides a continuous supply of air to workers within containment.

The breathing air system does not serve or support any safety function and has no safety design basis.

The breathing air system takes air from the service air system, purifies it and makes it available to workers.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.19 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be used for the breathing air system.

Table 2.11.19: Breathing Air System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Requirement	Inspection, Test, Analyses	Acceptance Criteria
1. Quality of air produced by breathing air system meets applicable OSHA standards.	1. Air quality shall be tested and compared with OSHA standards.	1. Air quality standards met.

2.11.20 Process Sampling System

Design Description

The Process Sampling (PS) System is designed to provide sampling of all principal fluid process streams associated with plant operation. Representative samples are taken for analysis and provide the analytical information required to monitor plant and equipment performance.

The PS System consists of:

(1) Permanently installed sampling nozzles and sample lines.

(2) Sampling panels with analyzers and associated sampling equipment.

(3) Provisions for local grab sampling.

(4) Permanent shielding.

(5) Casks for storing and transporting samples.

The seismic design and quality group classifications of sample lines and their components shall conform to the classification of the system into which they are connected, up to and including the block valve (or valves), or, in the case of the reactor water sampling lines, the second isolation valve. The downstream sampling lines are Quality Group D.

Sampling is available from the post-accident sampling station (PASS) following a LOCA or ATWS event. All PASS sampling valves are operated remotely. The PASS isolation valves are operated from the main control room using Class 1E power sources. All other valves are operated from the local control panel with two offsite power supplies.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.20 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be used by the PS System.

Table 2.11.20:

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The system has the capability to perform post-accident sampling.	1. Visual inspection (VI) will confirm that a post-accident sampling station (PASS) is provided.	1. The post-accident sampling station is provided.
2. The PASS isolation valves are connected to Class 1E sources. The PASS isolation valves may be opened for sampling during an accident without removing the LOCA signal.	2. VI will include the isolation valve electrical connections. Tests simulating a LOCA signal will be performed while the isolation valves are operated.	2. Plant tests and VI confirm Class 1E power sources and proper isolation valve operation under LOCA signals.
3. The PASS provides shielding and sample transporting casks.	3. VI of the PASS will review the presence of sample shielding.	3. Shielding and transporting casks are provided at the PASS.

2.11.21 Freeze Protection System

Design Description

The Freeze Protection System provides insulation, steam, and electrical heating for all external tanks and piping that may freeze during winter weather.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.11.21 provides definition of the inspection, tests, and/or analysis, together with associated criteria which will be undertaken for the Freeze Protection System.

Table 2.11.21: Freeze Protection System

Inspections, Tests, Analyses, and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Provide insulation, steam, and electrical heating for all external tanks and piping that may freeze during winter weather.	1. Visual inspection will be conducted to confirm that the insulation, steam, and electrical heat provisions are installed as required.	1. Confirmation that the required freeze protection has been installed.

2.11.22 Iron Injection System

No Tier 1 entry for this system.

2.12 Station Electrical

2.12.1 Electrical Power Distribution System

Design Description

The plant Electrical Power Distribution (EPD) System is a complete three-load group distribution system with two independent off-site power sources (Normal Preferred and Alternate Preferred), the Main Turbine Generator, three on-site Standby Power Sources (Emergency Diesel Generators), and a Combustion Turbine Generator (CTG) located on-site. This three-load group configuration, with multiple power sources, reduces the challenge to plant safety systems by increasing plant reliability. Any one of the three-load groups can safely shut down the plant and maintain safe shut down. The CTG provides an additional diverse power supply to back up safety system power supplies, if needed (Figure 2.12.1a).

During normal plant operation, the main generator supplies power to the Main Power Transformer (MPT) and the three Unit Auxiliary Transformers (UATs) through a main generator output breaker and an Isolated Phase Bus. When the main generator is off-line, power is supplied to the UATs from the MPT(Normal Preferred Power).

Each of the three UATs supplies power to a separate load group. One winding of each transformer supplies power to one non-essential medium voltage (6.9 kV) Power Generation (PG) switchgear and through a bus tie breaker to a Plant Investment Protection (PIP) switch- gear. The second winding supplies power to a second non-essential Power Generation medium voltage switchgear and to an Essential Safety System (ESS) medium voltage switchgear. Power from the UATs to the medium voltage switchgear of the three non-essential load groups and to the first set of medium voltage circuit breakers feeding the three essential medium voltage switchgear is supplied through Non-Segregated Phase Buses.

The Reserve Auxiliary Transformer (RAT) is the Alternate Preferred Power source and is preferably lined up to supply power to one of the three ESS switchgear. One winding of the transformer can supply power directly to three non-essential Power Generation (PG) and three non-essential Plant Invetment Protection (PIP) medium voltage switchgear and through bus tie circuit breakers to the other three non-essential Power Generation medium voltage switchgear. The second winding can supply power to all three Essential Safety System medium voltage switchgear (Divisions I, II, III). Power from the RAT to all of the medium voltage switchgear of the three essential and non-essential load groups is provided through Non-Segregated Phase Buses.

Each ESS (Divisions I, II, III) medium voltage switchgear is normally supplied power from its associated UAT or from the RAT. In addition to these power sources, each ESS medium voltage switchgear is provided with its own dedicated Standby Power Supply. In the event of low voltage on the switchgear bus (e.g., loss of off-site power), the associated Emergency Diesel Generator automatically starts and, after assuring that all other input feeder breakers are open, automatically connects to the bus to supply emergency power. Each emergency bus can also be supplied power from the CTG. All bus transfer operations to the Class 1E buses, except for the automatic connection of each dedicated emergency diesel generator, are manual only.

Each load group of non-essential medium voltage switchgear is supplied power from its associated UAT with an alternate supply from the RAT . In addition to these power sources, the three non-essential PIP medium voltage switchgear can be connected directly to the CTG. On loss of voltage to a pre-selected PIP bus, the CTG will automatically start and, after assuring that all other input feeder and bus tie breakers are open, automatically connects to the affected bus. However, only the two preselected buses of the three buses will connect automatically to the CTG. All other non-essential bus transfers are manual only.

Medium voltage Metal Clad Switchgear (M/C) supply power to large loads (typically larger than 300 kW) and one or more medium voltage (6.9 kV) to low voltage (480V) Power Center Switchgear (P/C) transformers in the same non-essential load group or safety division. Power Center Switchgear supply power to medium size loads (typically between 100 to 300 kW) and multiple low voltage (480V) Motor Control Centers (MCC) in the same non-essential load group or safety division. Motor Control Centers supply power to smaller loads (typically less than 100 kW), including lighting, 120 VAC instruments, power, and control equipment.

With one exception, ESS switchgear and non-essential system switchgear are not interconnected except by common non-essential medium voltage power supplies. The one exception is the Fine Motion Control Rod Drive Power Center Switchgear. One of the essential medium voltage switchgear supplies the preferred power to the non-essential Power Center through a series of one feeder circuit breaker and one transfer switch. The feeder breaker is Class 1E. The feeder cable, transfer switch, Power Center transformer, and interconnecting cable to the Power Center bus input breaker are classified as Associated 1E. One of the non-essential medium voltage PIP switchgear supplies the alternate power to the non-essential Power Center through a series of one feeder circuit breaker and the transfer switch. The feeder breaker, feeder cable (to the contacts of the transfer switch), transformer output breaker and Power Center are non-essential. Automatic transfer of the transfer switch is only from the essential to the non-essential power source on loss of essential bus voltage. Transfer back is manual only (Figure 2.12.1b).

Unit Auxiliary Transformers :

The size of each Unit Auxiliary Transformer (UAT) is selected such that it will provide the full power requirements of its associated load group without exceeding its air/oil rating during normal 100% plant operation (e.g., all three load groups available) and will not exceed its forced air/oil rating with one load group out of service during 100% plant operation. Each transformer has two secondary windings as described above and will provide power at 6.9 kV with a nominal input voltage of 27 kV. Transformer impedance is selected to limit the output voltage decrease to a maximum of 20% during the starting of large motors and to limit the fault current to less than the maximum interrupting capacity of the circuit breakers while maintaining the required bus voltage regulation. The three UATs are separated from each other and from the Main Power Transformer by shadow fire walls. The UATs are also separated from the Reserve Auxiliary Transformer by a minimum of 50 feet. Each UAT is provided with its own oil pit and drain. Grounding and lightning protection is provided.

Reserve Auxiliary Transformer:

The size of the Reserve Auxiliary Transformer (RAT) is selected such that one of the secondary windings will provide the power requirements of the loads on one half non-essential load group at 100% plant power operation and the second winding will provide the power requirements of all three divisions of Essential Safety System (ESS) loads without exceeding its air/oil rating. The transformer ratio and impedance is selected to provide 6.9 kV (+/-10%) with a maximum frequency variation of +/-2% at 0.9 power factor load and a maximum voltage decrease of 20% during the starting of large motors, assuming nominal input voltage and frequency. A frequency variation of two cycles is acceptable during periods of instability of the input. Impedance is also selected to limit the fault current to less than the maximum interrupting capacity of the circuit breakers while maintaining the required bus regulation. The RAT and its input feeders are separated from the Main Power Transformer and its input feeders and from the UATs by a minimum of 50 feet. The RAT is provided with its own oil pit and drain. Grounding and lightning protection is provided.

Switchgear and Breakers:

The Main Generator Circuit Breaker is sized to handle the main generator full load output at a nominal voltage of 27 kV and to interrupt the maximum calculated fault current occurring at the breaker. It is equipped with redundant trip coils supplied from separate non-essential on-site 125 VDC batteries and is located approximately midway between the Main Generator and the Main Power Transformer.

Each feeder from a UAT to its respective ESS switchgear is provided with a stub bus and circuit breaker to facilitate the transition from the Non-Segregated Phase Bus to cable.

All Metal Clad and Power Centers switchgear, and Motor Control Centers are identified according to their Essentiality, Load Group or Division and their voltage level (6.9 kV, 480V) and are physically separated accordingly. Divisional switchgear are qualified Essential Class 1E and are located in Seismic Category I structures and in their respective divisional electrical equipment rooms or fire areas. Essential equipment rooms and fire areas are separated by three-hour fire barriers. Non-essential switchgear are separated by appropriate distances between non-essential load groups. Switchgear and associated transformers (e.g., Power Centers) are selected for their intended service and load requirements and are rated to sustain the maximum calculated fault current under all modes of operation until the fault is cleared. Feeder and load circuit breakers are sized and rated to provide the load requirements under all expected operating modes and are capable of interrupting their maximum calculated fault currents. Both switchgear and associated transformers are grounded. In addition, each medium voltage Metal Clad switchgear is provided with a Safety Ground Circuit Breaker which is racked-out during normal operation and is interlocked with bus voltage and its related bus feeder breakers to prevent inadvertent closure. The breaker is annunciated in the main control room when it is in the racked-in position.

Switchgear and motor control centers are provided with the manufacturer's recommended fault current and protective devices as required by the fault current and breaker coordination analysis performed during the implementation stage of the design. Fault current and breaker coordination analysis for Class 1E equipment is coordinated with the non-essential equipment load groups. Analyses consider the impedance of interconnecting cables and buses, and load cables. Control and instrumentation power for each switchgear is provided from the associated divisional or non-essential power train 125 VDC battery. For power circuits providing power through primary containment penetrations, a redundant overcurrent protective device is provided in series with the circuit breaker if the calculated fault current could exceed the maximum continuous current rating of the penetration. In addition to the normal protective features, zone-select interlocks are provided on the input feeder breakers to the essential switchgear supplying power to the Fine Motion Control Rod Drive (FMCRD) Power Center. The interlocks are provided to delay tripping the essential switchgear input feeders until the normal overcurrent device on the feeder to the non-essential FMCRD Power Center has had time to trip and clear any fault.

Electrical power generation and distribution parameters needed to assure plant reliability and safe shutdown are provided in the Main Control Room and to the

Remote Shutdown System. These parameters include power distribution system breaker positions, voltages, amperes, kVA, kW, and power factor. In addition, remote control of selected power generation circuit breakers, including synchronizing capability, is provided in the control room.

Phase Buses and Cables:

The Isolated Phase Bus is selected to carry the Main Generator full load output at a nominal 27 kV and rated to sustain the maximum calculated fault current until the fault is cleared. Disconnect links are provided in the feeds to each of the UATs to facilitate maintenance and isolate a faulty transformer. A main generator breaker is also provided as described above. The Isolated Phase Bus housing is grounded at both the Main Generator and the Main Power Transformer ends of the bus.

The Non-Segregated Phase Buses are selected to carry the full load at 6.9 kV to which they will be subjected under all modes of operation and are rated to sustain the maximum calculated fault current until the fault is cleared. Buses are identified according to voltage level and load group and are grounded at the same point as the switchgear to which they connect.

Power Distribution System cables are selected for size and insulation based on their voltage, service load, routing, and environmental conditions, including temperature, humidity, and radiation, to which they may be exposed. Ratings and loading of the selected cables assures that they can sustain the maximum calculated fault currents to which they may be subjected until the fault is cleared. Cable impedance is considered in the overall distribution system protection analysis which will be performed during the implementation stage of the design. Selection and application of cables is intended to assure a life expectancy of 60 years. Cables are identified according to voltage levels, non-essential load group, essential division, and function.

Independence and Separation:

Electrical independence of equipment is provided by three separate load groups which are functionally redundant and capable of supporting plant operation at 50% of its rated output. There are no automatic connections between the load groups. Each load group is supplied by a separate power source unless connected to the Combustion Turbine Generator. Electrical independence of Essential Safety Systems is provided by three separate safety divisions with their own dedicated emergency diesel generator. There are no automatic bus ties or power supply transfers between divisions. Normal Preferred Power to each division is from a separate non-essential power transformer. The only on line connection between a safety division and a non-essential load is the divisional power feed (as described above) to the FMCRD Power Center.

Transformer and switchgear separation is described above. Essential Safety division cables are routed in Seismic Category 1 structures and dedicated divisional raceways which are separated from each other such that tolerance is provided for a complete burnout of a single fire area. Non-essential cables, if routed with divisional cables, are treated as Class 1E Associated. Cables of different divisions are not routed through a common hostile area except where justified by analysis (e.g., primary containment).

Separation of non-essential Normal Preferred and Alternate Preferred Power feeders is maintained by routing through different areas of the turbine and reactor buildings and by distance when routing across the control building. Non-essential load group separation between feeders from the UATs to the divisional switchgear is provided by routing cables in separate raceways.

A separate CTG feeder cable is provided to each of the three divisional and three non-essential switchgear to facilitate maintenance and fault clearance. CTG feeders to the reactor building follow a similar routing scheme to that used for the Alternate Preferred Power feeders.

In addition to the above separation, raceways are separated according to voltage levels and functions within divisions and load groups (e.g., low voltage control cables are routed separate from medium voltage power cables). Raceway are provided with grounding connections.

Grounding:

The electrical grounding system is comprised of: (1) an instrument grounding network for grounding of instrumentation and computer systems; (2) an equipment grounding network for grounding electrical equipment (e.g., switchgear, motors, distribution panels, cables, etc.) and selected mechanical components (e.g., fuel tanks, chemical tanks, etc.); (3) a lightning protection network for protection of structures, transformers and other equipment located outside buildings; and (4) a plant grounding grid. All grounding networks are insulated from each other and separately grounded to the plant grounding grid outside the structures. All grounding networks and equipment are low resistance grounded except the main generator, the emergency diesel generators, and the CTG, which are high resistance grounded to maximize availability. All components requiring grounding are identified and provided with grounding connections.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.12.1 provides a definition of the inspection, test, and/or analysis together with associated acceptance criteria which will be undertaken for the Electrical Power Distribution System.

Table 2.12.1: Electrical Power Distribution System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The electrical power distribution system is a three-load group distribution system with two off-site power supplies, three on-site emergency generators, a Combustion Turbine Generator located on site, and the main generator with its output circuit breaker.	1.a Inspections of the distribution system configuration will be performed to confirm each load group is supplied by a separate Unit Auxiliary Transformer.	1.a Each of the three-load groups is supplied power from a separate UAT.
An Isolated Phase Bus connects the Main Generator to the Main Power Transformer and Unit Auxiliary Transformers (UATs) through the Main Generator Breaker and through disconnect links to the UATs. Non-segregated Phase Buses connect the UATs and the RATs to their associated switchgear breakers and the first in-line breakers providing power to the Essential Safety System (ESS) switchgear.	1.b Inspections of the Isolated Phase Bus and Non-segregated Phase Bus Installations, including the main generator breaker and disconnect links to the UAT, will be performed.	1.b Isolated and Non-segregated Phase Buses, with associated main generator breaker and disconnect links, are provided.
Each UAT connects to two non-essential Power Generation switchgear and one ESS switchgear in its own load group. The RAT connects to three Power Generation, three PIP, and three ESS switchgear. The CTG connects to the three non-essential PIP and the three ESS switchgear. Each EDG only connects to its own ESS switchgear. (See Figures 2.12.1a and b)	1.c Inspections of the transformer and other power sources and their power feeders will be performed to confirm their location and connections to the specified switchgear.	1.c The transformers, emergency diesel generators, and Combustion Turbine Generator are located in accordance with the certified design and connect to the specified switchgear.

Table 2.12.1: Electrical Power Distribution System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
2. Unit Auxiliary Transformers are sized to provide full load requirements within their air/oil rating for 100% plant operation (with all three-load groups available) and will not exceed their forced air/oil rating with one load group out of service.	2.a Inspection of load assignments will be performed to assure transformer nameplate ratings will not be exceeded with all expected loads operating during either the two or three-load group operating mode.	2.a Transformer nameplate ratings will not be exceeded during two and three-load group operating modes.
UATs have two secondary windings and will provide a nominal voltage of 6.9 kV with a nominal input voltage of 27 kV. Output voltage will not exceed a 20% decrease from nominal during motor starting to assure at least the required minimum voltage at connected motor terminals.	2.b Inspections and tests will be conducted to confirm that transformer ratios provide output voltages on both windings that are consistent with the input voltage.	2.b Transformer ratios provide output voltages that are consistent with input voltages and output voltages do not decrease below 20% of nominal voltage when motors with the largest starting currents are started during expected load conditions.
3. The Reserve Auxiliary Transformer is sized to provide the full load requirements of one complete non-essential load group and all three Essential divisions without exceeding its air/oil rating.	3.a Inspection of load assignments will be performed to assure that transformer nameplate ratings will not be exceeded with all expected loads operating.	3.a Transformer nameplate ratings will not be exceeded when supplying power to one non-essential load group and three Essential divisions.
The RAT has two secondary windings and will provide a nominal output voltage of 6.9 kV +/-10% with the nominal input voltage provided. Output voltage will not exceed a 20% decrease from nominal during motor starting to assure at least the required minimum voltage at the connected motor terminals.	3.b Inspections and tests will be conducted to confirm that transformer ratios provide output voltages on both windings that are consistent with the input voltage.	3.b Transformer ratios provide output voltages that are consistent with input voltages and output voltages do not decrease below 20% of nominal voltage when motors with the largest starting currents are started during expected load conditions.

Table 2.12.1: Electrical Power Distribution System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4. Breakers are capable of interrupting the maximum fault current to which they may be subjected. Switchgear, Motor Control Centers, Isolated and Non-segregated Phase Buses, and cables are selected to sustain the maximum fault currents to which they may be subjected until the fault is cleared. Transformers are sized to limit maximum fault currents while maintaining required voltage regulation.	4.a Inspection of the connected load requirements and breaker coordination scheme will be performed to confirm the selection of the electrical power distribution system components and cables and their capability to limit and clear faults.	4.a Transformers, switchgear, motor control centers, phase buses, and cables are capable of sustaining the maximum fault currents to which they may be subjected until the fault is cleared. Circuit breakers are rated to interrupt the maximum fault currents to which they may be subjected.
Cables are sized and insulation selected to accommodate the load requirements, type of service, and environmental conditions to which they may be subjected.	4.b Inspection of the distribution system cable selection criteria will be performed to assure that sizing and insulation selection of cables is consistent with the load and environment to which they may be subjected.	4.b Cable selection is consistent with the cable selection criteria and will perform their intended service.
Switchgear and motor control center protection devices and breaker control power is provided from the 125VDC battery of the same division or load group or the power is internal to the switchgear. The main generator breaker control power is provided from two separate, on-site, non-essential 125VDC batteries.	4.c Inspection of power distribution system protective devices and control power supplies will be performed.	4.c Power distribution system protective devices and control power sources are either internal to the switchgear or from the 125 VDC battery of the same division or non-essential load group. The main generator breaker control power is supplied from two separate on-site, non-essential 125 VDC batteries.
Redundant overcurrent devices are provided for cables entering primary containment through penetrations, when required	4.d Inspection of the redundant overcurrent devices on cables penetrating the primary containment will be performed.	4.d Redundant overcurrent devices are provided, when required, on all electrical cables penetrating the primary containment.

Table 2.12.1: Electrical Power Distribution System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. Electrical independence is maintained between Essential Safety Systems.	5.a Inspections of the Essential Safety Systems will be performed to confirm their independence	5.a There are no bus ties between Essential Safety Systems.
Electrical independence is maintained between non-essential load groups.	5.b Inspections of the non-essential load groups will be performed to confirm their independence.	5.b There are no automatic bus ties between non-essential load groups.
Electrical independence is maintained between Essential Safety Systems and non-essential load groups. The one exception is the two power supplies to the Fine Motion Control Rod Drive (FMCRD) Power Centers	5.c Inspection of the configuration and protection scheme employed for the two power sources providing power to the FMCRD Power Center will be performed.	5.c The configuration and protection employed on the essential and non-essential feeders to the FMCRD Power Center provide the required electrical independence and separation.
6. All switchgear, phase buses, and cables are identified according to Essential Safety Division, Divisional Association, Non-essential load group, voltage level and, when required, function; and are separated accordingly.	6.a Inspections of switchgear, phase buses, power distribution and control cables will be performed to confirm that they are identified according to their Essential division, divisional association, non-essential load group, voltage levels, and functions.	6.a Power distribution system components and cables are identified according to division, association, load group, voltage level, and function.

Table 2.12.1: Electrical Power Distribution System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. (Continued) ESS divisional equipment is Class 1E and is located in Seismic Category 1 structures and divisional equipment areas which are physically separated by three hour fire barriers. Divisional cables are Class 1E and are routed in Seismic Category 1 structures and dedicated raceways which are separated such that tolerance is provided for complete burnout of a single fire area. Cables of different divisions are not routed through a common hostile area except where justified. Non-essential cables, if routed with Essential cables are Class 1E Associated.	6.b Inspection of the locations, separation, and identification of Essential power distribution system components and raceways will be performed.	6.b Essential power distribution system components are located in Seismic Category 1 structures and separated divisional raceways and fire areas. Separation is provided between divisions, voltage levels, and functions.
	6.c Inspections will be performed to identify all associated circuits	6.c Class 1E Associated circuits are identified and comply with Class 1E requirements
Non-essential load group equipment is non-essential and separated by distance. The Normal Preferred Power and Alternate Preferred Power feeders are routed through different areas of the Turbine and Reactor Buildings and by distance when crossing the Control Building.		
The three Normal Preferred Power feeders are separated by routing in separate raceways. CTG feeders follow a similar routing scheme as that used for the Alternate Preferred Power feeders to separate them from the Normal Preferred Power.	6.d Inspections of the separation provided for the Normal Preferred Power, Alternate Preferred Power, and Combustion Turbine Generator feeders will be performed.	6.d Separation is provided between the Normal Preferred Power feeders and the Alternate Preferred Power and CTG feeders and between the Normal Preferred Power feeders of the three load groups.

Table 2.12.1: Electrical Power Distribution System (Continued)

Insp ections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. (Continued) UATs are separated from each other and from the Main Power Transformer by shadow fire walls and from the RAT by a minimum of 50 feet. The Main Power Transform RAT and its feeder by a minimum of 50 feet. Essential division and non-essential load group raceways are separated according to voltage levels and functions, when required. Medium voltage power cables are not routed in the same raceway as control cables.	6.e Inspection of the separation between the Main Power Transformer, the Unit Auxiliary Transformers, and the Reserve Auxiliary Transformer will be performed.	6.e A minimum 50-ft separation is provided between the Main Power and Reserve Auxiliary Transformers, and between the Unit Auxiliary Transformers and the RATs. The Main Power and RAT transmission lines are separated by a minimum of 50 feet. Shadow fire walls separate the UATs from each other and from the Main Power Transformer.
7. The electrical grounding system is comprised of separate grounding and lightning protection networks. These networks are instrument, equipment, lightning protection, and a plant grounding grid. The instrument equipment, and lightning protection networks are insulated from each other and separately connected to the plant grounding grid outside the structures. All electrical and mechanical components requiring grounding are identified and low resistance grounded to the appropriate grounding network. The Main Generator, Emergency Diesel Generators, and Combustion Turbine Generator are high resistance grounded to maximize availability. Equipment located outside structures are grounded locally and provided with lightning protection, when required.	7.a Inspection and tests will be performed on the grounding networks and lightning protection system to confirm that they are insulated from each other and low resistance grounded and that all equipment requiring grounding are identified.	7.a Grounding networks and lightning protection systems are insulated from each other and connected to the plant grounding grid outside structures. Equipment requiring grounding is identified and low resistance grounded except for the Main Generator, the Emergency Diesel Generators, and the Combustion Turbine Generator, which are high resistance grounded.

Table 2.12.1: Electrical Power Distribution System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. (Continued) Medium voltage switchgear are provided with a Safety Ground Circuit Breaker which is interlocked with the bus voltage and the bus input feeder breakers and is annunciated in the control room when in the racked-in position.	7.b Inspection and test of the Safety Ground Circuit Breakers protection scheme will be performed.	7.b Safety Ground Circuit Breakers are interlocked with the bus voltage and bus input feeder breaker positions to prevent inadvertent closure. Annunciation is provided in the main control room when a breaker is in the racked-in position.
8. Power distribution system remote control, parameter information, and annunciators are provided in the Main Control Room and to the Remote Shutdown System for required plant operation and safety shutdown of the plant.	8. Inspections of the controls and information provided to the Main Control Room and Remote Shutdown System will be performed to assure plant control and information needs are provided for plant operation and safe shutdown.	8. Necessary controls and information are provided in the Main Control Room for safe operation and Safety Shutdown of the plant.
9. All Bus transfer operations are manual only, except for automatic bus transfer on the divisional buses form their normal power supplies to their respective Emergency Diesel Generators, automatic bus transfer on the Plant Investment Protection buses from their normal power supplies to the Combustion Turbine Generator, and the automatic bus transfer from the Essential divisional bus to the Plant Investment Protection bus for the Fine Motion Control Rod Drive Power Center. All automatic bus transfers are dead bus transfers and are initiated on bus low voltage.	9. Testing will be performed to confirm that all bus transfers are manual only, except for the specified automatic bus transfers on the Emergency, Plant Investment Protection, and FMCRD Power Center switchgear when bus low voltage occurs.	9. Bus transfers are automatic for Safety System transfers to the Emergency Diesel Generators, PIP bus transfers to the Combustion Turbine Generator, FMCRD Power Center transfer to the non-essential power source. Bus transfers occur on bus low voltage. All other bus transfers are by manual operation only.
10. Essential Class 1E valve motors fed from the Motor Control Centers are provided with thermal overload protection which is bypassed during a Loss of Coolant Accident (LOCA) only. The thermal overload bypass is separately testable.	10. Testing will be performed to assure Class 1E valve motor thermal overloads will be bypassed when a LOCA signal is received and are operable under all other conditions.	10. Class 1E valve motor thermal overloads are bypassed on receiving a LOCA signal and are operable under all other conditions.

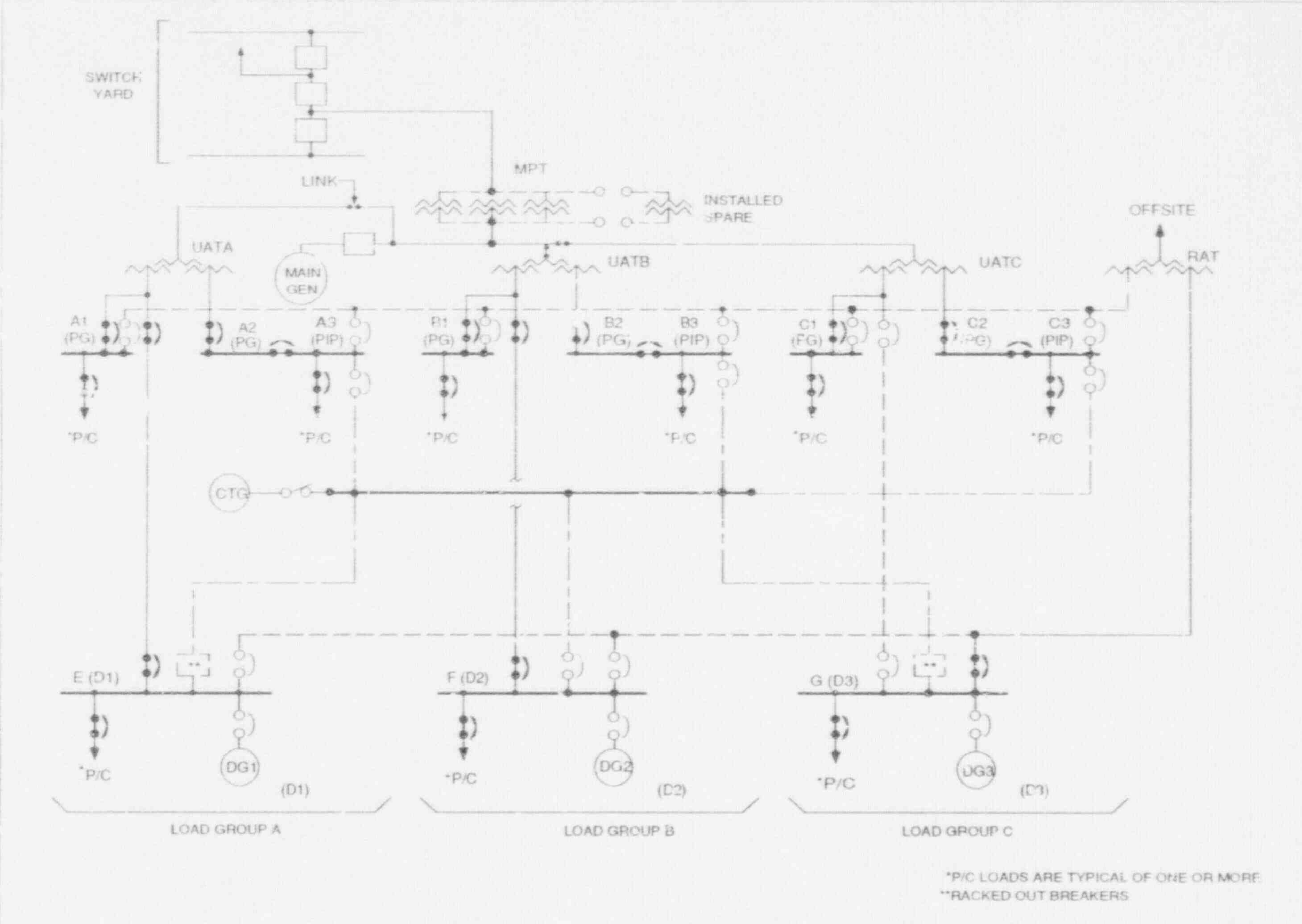


Figure 2.12.1a Electrical Power Distribution System

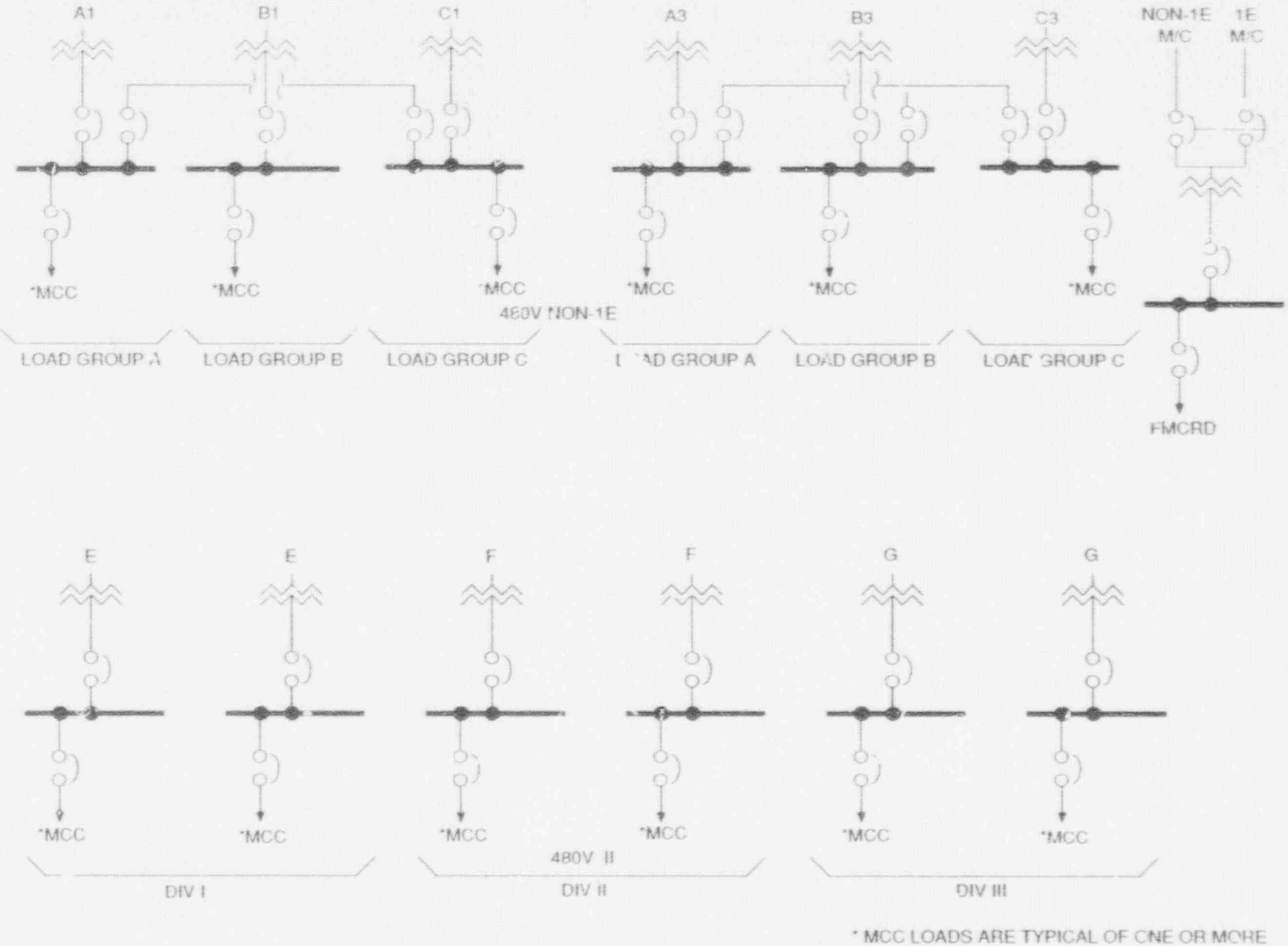


Figure 2.12.1b Electrical Power Distribution System

2.12.2 Unit Auxiliary Transformer

No entry. Covered by item 2.12.1.

2.12.3 Isolated Phase Bus

No entry. Covered by item 2.12.1.

2.12.4 Nonsegregated Phase Bus

No entry. Covered by item 2.12.1.

2.12.5 Metal Clad Switchgear

No entry. Covered by item 2.12.1.

2.12.6 Power Center

No entry. Covered by item 2.12.1.

2.12.7 Motor Control Center

No entry. Covered by item 2.12.1.

2.12.8 Raceway System

No entry. Covered by item 2.12.1.

2.12.9 Grounding Wire

No entry. Covered by item 2.12.1.

2.12.10 Electrical Wiring Penetrations

Design Description

Electrical wiring penetrations are provided for Primary Containment, and Secondary Containment, and fire barriers. Primary Containment penetrations are leak tested for mechanical integrity in accordance with the leak test requirements of the primary containment.

Primary Containment Penetrations

All electrical cables penetrating primary containment are provided with redundant overcurrent devices (e.g. fuses) in series with the circuit breakers when the maximum fault current can exceed the continuous current rating of the penetration. The redundant overcurrent devices are provided as backup protection for fault currents in the penetration in the event of circuit breaker overcurrent or fault protection failure. Redundant overcurrent protection devices are located such that a failure of one device will not disable the other. When a both redundant overcurrent devices are active devices (e.g. circuit breakers), separate trip coil power supplies are provided. Primary containment penetrations are separated between divisions by 3 hour fire barriers (e.g. separate rooms and floors) outside the containment and by distance inside the inerted containment. Divisional and non-divisional penetration separation is maintained in the same manner as raceway separation. Voltage groupings in penetrations is the same as that employed in raceways.

Secondary Containment and Fire Barrier Penetrations

Secondary containment electrical penetrations are provided for conduit and other raceways through secondary containment walls, floors, between fire areas, and for bottom entry through fire barriers into panels and switchgear. Integrity is maintained between fire areas by filling the penetration area around cables and around the raceway with a fire retardant foam. Electrical penetrations are curbed when penetrating floors and cable tray risers are self draining to prevent water column buildup in the riser. Penetrations in radiation areas are offset on each side of the barrier to prevent radiation streaming through the penetration.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.12.10 provides a definition of the Inspections, Tests, and/or Analysis, together with the associated Acceptance Criteria which will be undertaken for the Electrical Wiring Penetrations.

Table 2.14.1, Primary Containment System, provides a definition of the Inspections, Tests, and/or Analysis, together with the associated Acceptance

Criteria which will be undertaken for the Electrical Wiring Penetration Leak testing.

Table 2.12.10: Electrical Wiring Penetrations

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Electrical cables penetrating primary containment are provided with redundant overcurrent protection devices when the fault current can exceed the maximum continuous current rating of the penetration. The overcurrent devices are located such that a failure of one of the fault current devices cannot prevent the functioning of the redundant device. If both redundant devices require control power for tripping, they will be provided from separate control power sources. In addition, primary containment penetrations are separated between divisions by 3 hour fire barriers outside containment and by distance inside containment. Divisional and non-divisional penetrations are separated in the same manner as raceway separation. Voltage separation is maintained consistent with the voltage levels identified for raceways.	1.a For each primary containment penetration requiring redundant fault current protection, analyses of the fault clearing time curves for the primary and secondary overcurrent interrupting devices plotted against the thermal capability curve of the penetration will be performed to assure that the coordination of the devices will provide the necessary penetration fault current protection.	1.a Analyses show that redundant fault current protection devices will prevent fault currents from exceeding the continuous current rating of primary containment electrical penetrations.
	1.b Inspection of the electrical documentation will be performed to assure that the failure of one redundant overcurrent devices will not disable the function of the other and that the redundant overcurrent devices (e.g. circuit breakers) are provided control power for tripping from separate sources.	1.b Redundant electrical penetration fault current protection devices are installed such that the failure of one device will not disable the redundant device. Redundant devices are provided control power for tripping from separate sources when both devices require tripping power.
	1.c Inspection of the primary containment penetration locations will be performed to assure that electrical penetrations outside the containment are separated between divisions by 3 hour fire barriers and by distance inside the containment and that divisional and non-divisional penetration separation is the same as that used for raceways.	1.c Primary containment penetrations are separated between divisions outside the containment by 3 hour fire barriers and by distance inside containment. Divisional and non-divisional penetrations are separated in the same manner a raceways.

Table 2.12.10: Electrical Wiring Penetrations (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
2. Electrical cable raceways penetrating secondary containment or fire barrier walls and floors are provided with penetration seals. Penetration integrity is maintained by filling the area around the cables and around the raceway with a fire retardant foam. Raceway floor risers are curbed and self draining to prevent a water column buildup in the raceway. Electrical penetrations in radiation areas are offset on each side of the barrier to prevent radiation streaming.	2. Inspection of secondary containment and fire barrier electrical penetrations will be performed to assure they are installed in accordance with design installation specifications and prevent radiation streaming through the penetration in radiation areas.	2. Secondary containment and fire barrier electrical penetrations seals are provided and radiation streaming between areas is prevented.

2.12.11 Combustion Turbine Generator

Design Description

The Combustion Turbine Generator (CTG) is a non-essential standby power source located on-site within the turbine island. The turbine generator unit is sized to provide standby electrical power to any two of the non-essential plant investment protection (PIP) buses or one PIP bus and one Essential Safety System (Division) bus and their associated loads at a nominal voltage of 6.9 kV and 60 cycles during loss of off-site power to the bus. The CTG is not required for safe shutdown or maintenance of safe shutdown of the plant under any condition. Transfer to the CTG power supply is automatic for either or both of a preselected pair of PIP buses on loss of bus voltage. Transfer of the CTG power supply to any one of the divisional safety buses is manual and only performed after assuring that the safety-related power source has failed and no more than one PIP bus is being powered by the CTG.

The CTG is provided with an output disconnect switch for maintenance and feeds a stub bus where individual cables are connected to provide power to any of the three non-essential PIP buses or three essential divisional buses. In the unlikely event of multiple power source failures, this configuration also provides, with appropriate controls, the capability of using the CTG feeder cables as a vehicle for connecting any power source to any load(Figure 2.12.11).

The CTG unit is a skid mounted unit. It is equipped with its own auxiliary control and support systems (e.g., hydraulic start, excitation, lubrication, cooling, intake and exhaust, control and protective systems, control panel, etc.). Fuel is provided from an external fuel storage tank similar to that provided for an emergency diesel generator. Fuel is the same type and quality as that used by the diesel generators.

The CTG is designed to automatically start on a decrease of bus voltage to 70% of nominal, on either of the two preselected PIP buses, and be up to rated conditions and ready to load within a specific start time after receiving a start signal. The CTG will automatically provide power to the preselected PIP buses only.

CTG voltage and frequency regulation is the same as that provided by the non-essential 6.9 kV power distribution system. Sudden applications of large loads will not result in a voltage decrease from nominal voltage greater than 25%. Analysis to determination the need, if any, for load sequencing will be performed during the implementation stage of the design.

Controls, instrumentation, and alarms are provided in the control room to manually control and monitor the performance of the CTG.

The GTG is high resistance grounded to maximize availability.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.12.11 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria that will be undertaken for the CTG.

Table 2.12.11: Combustion Turbine Generator

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The Combustion Turbine Generator is capable of supplying full load power to any two Plant Investment Protection (PIP) buses or any one plant investment protection bus and any one essential safety bus (Figure 2.12.11).	1.a Inspection will be performed to confirm that the maximum expected combined loads on the two heaviest loaded buses are within the load rating of the combustion turbine generator.	1.a The combined maximum operating load of the two heaviest loaded buses do not exceed the rated power output (according to the nameplate rating) of the combustion generator.
	1.b Testing will be conducted by sychronizing the combustion generator to the off-site system and increasing its output to its full load condition.	1.b The unit produces rated output at rated voltage and frequency for a minimum of 24 hours. (momentary transients excepted).
2. Sudden applications of large loads will not result in more than a 25% voltage decrease from nominal voltage.	2. Testing will be conducted by sudden application of the largest load block.	2. The sudden application of the largest load block to the unit does not cause a voltage decrease in excess of 25% from nominal voltage.
3. Controls, instrumentation, and alarms are provided in the control room to operate and monitor performance of the combustion generator.	3. Inspection of instrumentation and testing will be conducted by operation of the Combustion Turbine Generator from the main control room.	3. The unit can be controlled, loaded and monitored from the main control room.

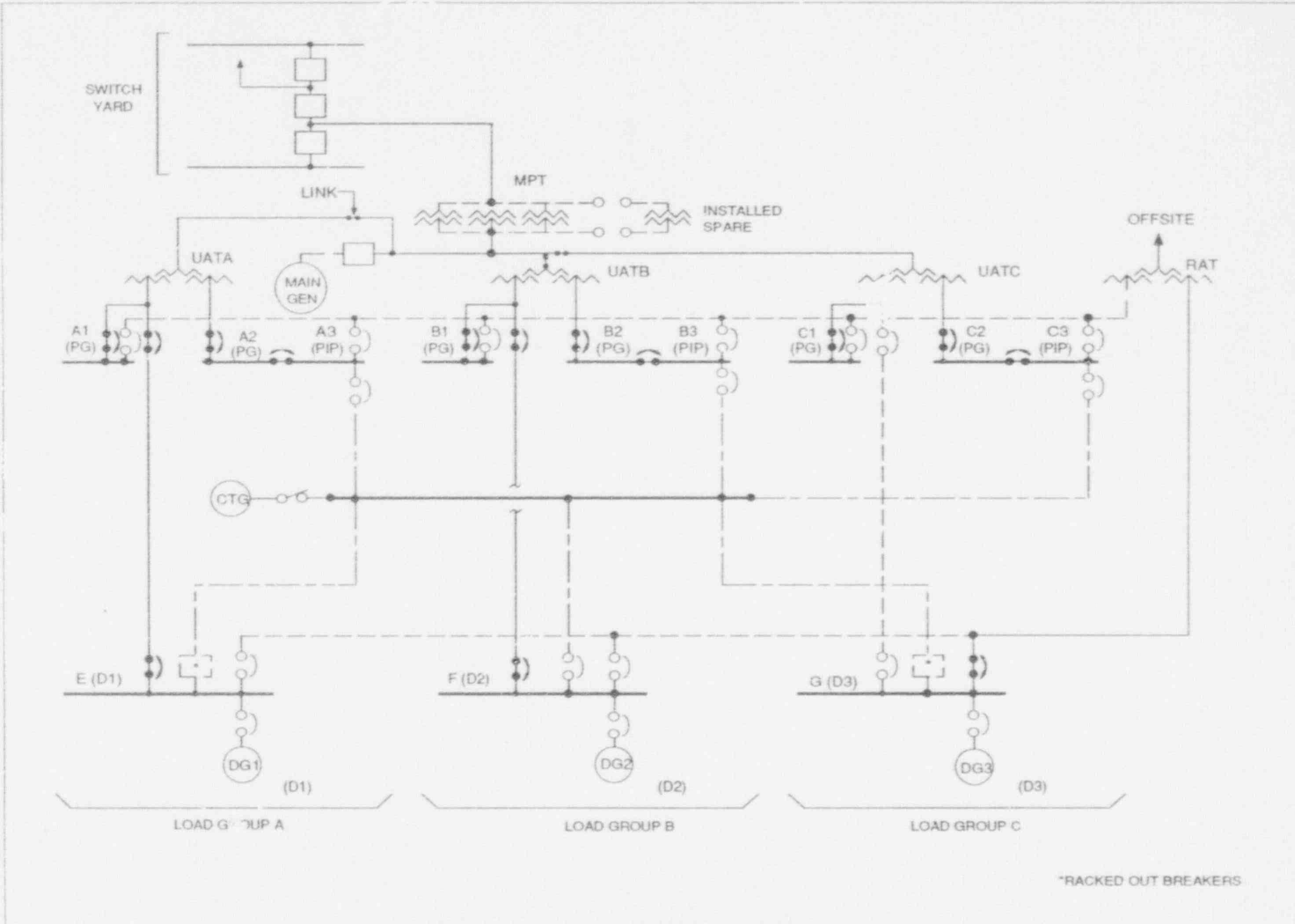


Figure 2.12.11 Combustion Turbine Generator

1

IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

2.12.12 Direct Current Power Supply

Design Description

The plant Direct Current (DC) Power Supply System consists of safety-related 125 VDC and non-safety-related 125 VDC and 250 VDC power supply systems. The system batteries are comprised of industrial type storage cells. (See Figures 2.12.12a, b, and c.)

Safety-Related DC Power

The safety-related DC power distribution system consists of four Class 1E, separated and electrically independent, divisional distribution systems located in Seismic Category I structures. Each division contains its own 125 VDC battery, associated central distribution panel, motor control center (if needed for larger loads), and distribution panels local to the supplied loads. Each battery is separately housed in its divisional area and in a ventilated room apart from its chargers and distribution equipment. Each battery is selected such that its warranted capacity will provide 100 percent of its design loads at the end-of-installed-life with a minimum allowable voltage of 105 VDC. The batteries in safety divisions 2, 3, and 4 are sized to supply all required loads for a minimum of 2 hours without recharging and the battery in division 1 is sized to supply required loads (including RCIC loads) for 8 hours of coping during station blackout. The division 1, 2, and 3 batteries are each provided with a normal battery charger supplied from a motor control center (MCC) in the same division. The division 4 battery charger is supplied from the division 1 MCC. In addition, a standby battery charger is shared between divisions 1 and 2 and a second standby charger is shared between divisions 3 and 4. The battery charger circuit breakers are interlocked such that paralleling between divisions, either at the AC supply inputs or DC outputs, is prevented. Each battery charger is a self load limiting battery replacement type and is sized to supply the normal steady state loads while restoring the battery to a full charged state at a maximum charging voltage of 140 VDC.

Non-Safety-Related DC Power

The non-safety-related DC power distribution system consists of three non-divisional 125 VDC distribution systems (one per load group) and one 250 VDC distribution system. Each 125 VDC system contains its own battery, associated central distribution panel, and distribution panels local to the supplied loads. Each battery is separately housed in a ventilated room apart from its chargers and distribution equipment. Each battery is selected such that its warranted capacity will provide 100 percent of its design loads at the end-of-installed-life with a minimum allowable voltage of 105 VDC. The batteries in each load group are sized to supply all required loads for a minimum of 2 hours without recharging. Each battery is provided with a normal battery charger supplied from a motor control center (MCC) in the same load group. In addition, a standby battery charger is shared between all three load groups such that it can be powered from an MCC in any load group and feed any of the three 125 VDC non-essential central distribution panels for load supply or battery charging. Each battery charger is a self load limiting battery replacement type and sized to supply the normal steady state loads while restoring the battery to a full charged state at a maximum charging voltage of 140 VDC. The battery charger circuit breakers are interlocked such that paralleling between any load group at the AC supply inputs or paralleling batteries is prevented. This battery charger interlock configuration, with additional interlocks on the central distribution panel bus tie circuit breakers, provides the ability for any battery or battery charger to supply any central distribution panel while preventing the batteries from being paralleled.

In addition to the 125 VDC non-essential power distribution systems, a single 250 VDC non-essential power distribution system is provided to supply the plant computer systems and other non-essential DC loads (e.g. turbine turning gear, lube oil pumps). The battery is housed in a ventilated room separate from its battery chargers and distribution panels. The battery is selected such that its warranted capacity will provide 100 percent of its design loads at the end-of-installed-life with a minimum allowable voltage of 210 VDC and sized to supply all required loads for a minimum of 2 hours without recharging. Two battery chargers are provided. The normal charger is powered from either of two different non-essential load group Power Centers (P/C) through an interlocked, manual bus transfer device to prevent paralleling of the load group P/Cs. A smaller standby battery charger is powered from a control building motor control center (MCC). The battery charger outputs are interlocked to prevent paralleling the chargers. Each battery charger is a self load limiting battery replacement type. The normal battery charger is sized to supply the normal steady state loads while restoring the battery to a full charged state at a maximum charging voltage of 280 VDC. The standby battery charger is sized to provide the normal loads during battery and normal charger maintenance.

The DC motor control centers, central distribution panels, and local distribution panels are identified according to their essentiality (e.g. essential division 1,2,3,4 or non-essential load group A,B,C) and are located in their respective electrical equipment rooms or fire areas. Essential equipment rooms and fire areas are separated by three hour fire barriers. MCCs and panels are selected for their intended service and load requirements and are rated to sustain the maximum calculated fault current under all modes of operation until the fault is cleared. Feeder and load circuit breakers are sized and rated to provide the load requirements under all expected operating modes and are capable of interrupting their maximum calculated fault currents. Switchgear and panels are grounded in accordance with the plant grounding specification. MCCs are provided with the manufactures recommended fault current and protective devices as required by the fault current and breaker coordination analysis performed during the implementation stage of the design.

Control and instrumentation power for each switchgear is provided from the associated divisional or non-divisional battery. For circuits providing power through primary containment penetrations, a redundant overcurrent protective device (generally a fuse) is provided in series with the circuit breaker if the calculated fault current could exceed the maximum continuous current rating of the penetration. Electrical power distribution parameters needed to assure plant reliability and safe shutdown (as determined during the implementation stage of the design) are provided in the Main Control Room. Power distribution system cables are selected for size and insulation based on their voltage, service load, routing, and environmental conditions (e.g. temperature, humidity, radiation) to which they may be exposed. Ratings and loading of the selected cables assures that they can sustain the maximum calculated fault currents to which they may be subjected until the fault is cleared. Cable impedance is considered in the overall distribution system protection analyses which will be performed during the implementation stage of the design. Selection and application of cables is intended to assure a life expectancy of 60 years. Cables are identified according to function (e.g. power, control), and essentiality (e.g. color coded) and are routed in the appropriate divisional or non-essential load group raceways.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.12.12 provides a definition of the inspection, test, and/or analysis together with the associated acceptance criteria which will be undertaken for the direct current (DC) power supply batteries and battery charging systems.

Table 2.12.1, Electrical Power Distribution System, provides a definition of the inspection, test, and/or analysis together with the associated acceptance criteria which will be undertaken for the direct current (DC) power supply distribution systems (e.g. raceways, cable and other equipment identification, grounding).

Table 2.12.12: Direct Current (DC) Power Supply

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The safety-related DC Power Distribution System consists of four Class 1E, separated and electrically independent divisions located in Seismic Category I structures. Each division contains its own 125 VDC industrial type storage battery, battery charger, central distribution panel, motor control center (when needed for large loads), and distribution panels local to the supplied loads. Each battery is separately housed in its respective divisional area and in a ventilated room apart from its battery chargers and distribution equipment. Each battery is selected such that its warranted capacity will provide 100 percent of its design loads at the end-of-installed-life with a minimum allowable voltage of 105 VDC. The Division 2,3, and 4 batteries are sized to supply all required loads for a minimum of 2 hours without recharging. The Division 1 battery is sized to supply required loads for 8 hours of coping during station blackout.	1.a Inspections of the safety-related distribution system arrangement will be performed to confirm each divisional battery is separately housed in a ventilated area apart from its associated distribution equipment and all equipment is located in its associated divisional areas in Seismic Category I structures. 1.b Testing will be performed to verify that each battery capacity is sufficient to satisfy the safety load demand profile under conditions of LOCA and loss of preferred power.	1.a Each divisional battery is separately housed in a ventilated area apart from its distribution equipment and all equipment is located in their respective divisional areas in Seismic Category I structures. 1.b Testing confirms that each battery capacity is sufficient to supply its safety load demand.

Table 2.12.12: Direct Current (DC) Power Supply (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
Each battery is provided with a divisional normal battery charger and a shared standby battery charger. The chargers are supplied from a motor control center (MCC) in the same division as the battery, except for the division 4 battery chargers which are supplied from a division 1 MCC. The standby battery chargers are shared. Divisions 1 and 2 share one standby charger and divisions 3 and 4 share a second standby charger. Battery charger circuit breakers are interlocked such that paralleling between divisions, either at the AC input or DC output, is prevented. Each battery charger is a self load limiting battery replacement type and is sized to supply normal steady state loads while restoring the battery to a full charge state at a maximum charging voltage of 140 VDC. (See Figure 2.12.12a.)	1.c A load capacity analyses will be performed showing each battery terminal voltage and worst case DC load terminal voltage at each step of the battery loading profile to assure that the battery will provide a minimum 105 VDC for the duration of the profile.	1.c The load capacity analyses confirms that each battery supplies the design loads at or above the required minimum voltage and is consistent with the manufacturer's ampere-hour ratings for the battery at a 2 hour and 8 hour rate.
	1.d Inspections of the normal and standby battery charger ratings (as identified by their nameplates) will be performed to confirm their capacity to supply normal steady loads and recharge their respective battery at a maximum voltage of 140 VDC.	1.d Battery charger nameplate ratings confirm their capacity to supply normal steady state loads and recharge the connected battery at a maximum voltage of 140 VDC.
	1.e Tests will be performed to confirm that the battery charger interlocks will prevent paralleling AC or DC divisions.	1.e Tests confirm that divisions cannot be paralleled, either AC and DC, through the battery chargers.
2. The non-safety-related DC Power Distribution System consists of three non-divisional 125 VDC (one per load group) systems and one 250 VDC distribution systems. Each 125 VDC system contains its own industrial type storage battery, central distribution panel, motor control center (when needed for large loads), and distribution panels local to the supplied loads. Each battery is separately housed in its respective ventilated room apart from its battery chargers and distribution equipment.	2.a Inspections of the non-safety-related distribution system arrangement will be performed to confirm each battery is separately housed in a ventilated area apart from its associated distribution equipment.	2.a Each of the batteries is separately housed in a ventilated area apart from its distribution equipment.

Table 2.12.12: Direct Current (DC) Power Supply (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
Each battery is selected such that its warranted capacity will provide 100 percent of its design loads at the end-of-installed-life with a minimum allowable voltage of 105 VDC. The batteries are sized to supply all required loads for a minimum of 2 hours without recharging.	2.b A load capacity analyses will be performed showing each battery terminal voltage and worst case DC load terminal voltage at each step of the battery loading profile to assure that the battery will provide a minimum 105 VDC for the duration of the profile.	2.b The load capacity analyses confirms that each battery supplies the design loads at or above the required minimum voltage and is consistent with the manufacturer's ampere-hour ratings for the battery at a 2 hour rate.
Each battery is provided with a normal battery charger supplied from a motor control center (MCC) in the same load group. A standby battery charger is shared with all three load groups. The standby battery charger can be powered from an MCC in any one of the three load groups and supply any of the three non-essential central distribution panels for load supply or battery charging. Battery charger and central distribution panel feeder and bus tie circuit breakers are interlocked such that paralleling load groups at the AC supply inputs or paralleling batteries is prevented. Each battery charger is a self load limiting battery replacement type and is sized to supply normal steady state loads while restoring the battery to a full charge state at a maximum charging voltage of 140 VDC. (See Figure 2.12.12b.)	2.c Inspections of the normal and standby battery charger ratings (as identified by their nameplates) will be performed to confirm their capacity to supply normal steady loads and recharge their respective battery at a maximum voltage of 140 VDC. 2.d Tests will be performed to confirm that the battery charger interlocks will prevent paralleling AC load groups or DC batteries.	2.c Battery charger nameplate ratings confirm their capacity to supply normal steady state loads and recharge the connected battery at a maximum voltage of 140 VDC. 2.d Tests confirm that AC load groups or DC batteries cannot be paralleled.

Table 2.12.12: Direct Current (DC) Power Supply (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3. The non-safety-related 250 VDC Power Distribution System consists of one 250 VDC industrial type storage battery, central distribution panel, motor control center, and distribution panels local to the supplied loads. The battery is separately housed in a ventilated room apart from its battery chargers and distribution equipment.	3.a Inspections of the non-safety-related distribution system arrangement will be performed to confirm the battery is separately housed in a ventilated area apart from its associated distribution equipment.	3.a The battery is separately housed in a ventilated area apart from its distribution equipment.
The battery is selected such that its warranted capacity will provide 100 percent of its design loads at the end-of-installed-life with a minimum allowable voltage of 210 VDC. The battery is sized to supply all required loads for a minimum of 2 hours without recharging.	3.b A load capacity analyses will be performed showing battery terminal voltage and worst case DC load terminal voltage at each step of the battery loading profile to assure that the battery will provide a minimum 210 VDC for the duration of the profile.	3.b The load capacity analyses confirms that the battery supplies the design loads at or above the required minimum voltage and is consistent with the manufacturer's ampere-hour ratings for the battery at a 2 hour rate.
The battery is provided with a normal battery charger supplied from two different non-essential load group Power Centers (P/C) through an interlocked bus transfer device to prevent paralleling AC load groups. The battery charger is a self load limiting battery replacement type and is sized to supply normal steady state loads while restoring the battery to a full charge state at a maximum charging voltage of 280 VDC. A smaller standby battery charger, powered from a control building MCC, is also provided and sized to supply normal steady state loads during battery maintenance. The two battery charger outputs are interlocked to prevent paralleling chargers.	3.c Inspections of the normal and standby battery charger ratings (as identified by their nameplates) will be performed to confirm their capacity to supply normal steady loads and the normal charger's capacity to recharge the battery at a maximum voltage of 280 VDC while supplying loads.	3.c Battery charger nameplate ratings confirm their capacity to supply normal steady state loads and the normal charger's capacity to recharge the battery at a maximum voltage of 280 VDC while supplying loads.
(See Figure 2.12.12c.)	3.d Tests will be performed to confirm [illegible] the battery charger interlocks will pre[illegible] paralleling AC load groups or battery chargers.	3.d Tests confirm that AC load groups or battery chargers cannot be paralleled.

2.12.13 Emergency Diesel Generator System (Standby AC Power Supply)

Design Description

The Class 1E diesel generators comprising the Division I, II, and III standby AC power supplies are designed to restore power to their respective Class 1E distribution system divisions as required to achieve safe shutdown of the plant and/or to mitigate the consequences of a loss-of-coolant accident (LOCA) in the event of a coincident loss of normal electrical power. Each of the three divisions of the AC power system has its own diesel generator.

The major loads consist of the following systems for all three divisions: Residual Heat Removal (RHR) System, Reactor Building Cooling Water (RCW) System, HVAC Emergency Cooling Water (HECW) System, and Reactor Service Water (RSW) System. In addition, Divisions II and III include the High Pressure Core Flooder (HPCF) System loads. (The Division I RCIC System is also part of the ECCS network, but is steam-driven and therefore does not present significant load to the diesel generator.)

Each Class 1E diesel generator, with its auxiliary systems (i.e, Fuel Oil Storage and Transfer System, Jacket Cooling Water System, Starting Air System, Lubrication System, and Combustion Air Intake and Exhaust System), supplies standby AC power to various Class 1E loads through the 6.9 kV and 480V systems. The 480V system, in turn, supplies power to the UPS and battery charger for the division's 120 VAC and 125 VDC safety loads. (The low voltage portion does not significantly contribute to diesel generator loading, but is included with "other 480V loads" per Figure 2.12.13.) Each is physically and electrically isolated from the other divisions. No automatic interconnection is provided between the Class 1E divisions. Each diesel-generator set is operated independently of the other sets, and is connected to the utility power system by manual control only during testing or for bus transfer. A failure of any component of one diesel generator set will not jeopardize the capability of either of the two remaining diesel generator sets to perform their functions. The diesel generators and their essential support equipment are classified Seismic Category 1, and are qualified for the environments where located. All components except for the fuel storage tanks and fuel transfer equipment are located within the Reactor Building.

Each diesel generator unit is rated at 6.9 kV, 60 Hz, and is capable of automatically starting, accelerating, attaining rated frequency and voltage within 20 seconds, and supplying its loads in the sequence and timing specified in the plant design documents. In addition, each diesel generator is capable of starting, accelerating and running its largest motor at any time after the automatic loading sequence is completed, assuming that the motor had failed to start initially. Each diesel generator unit is also reliability tested by the manufacturer.

The diesel generators start automatically on loss of bus voltage. Under-voltage sensors are used to start each diesel engine in the event of a sustained drop in bus voltage below 70% of the nominal 6.9 kV rating of the bus. Low-water-level sensors and drywell high-pressure sensors in each division are also used to initiate the respective diesel start under accident conditions. However, the diesels will remain on standby (i.e., running at rated voltage and frequency, but unloaded) unless the bus under-voltage sensors trigger the need for bus transfer to the diesel supply. Manual start capability (without need of DC power) is also provided.

Each diesel is supplied by its own independent fuel storage tank, which is located in an area protected from natural phenomena. This tank has a fuel capacity sufficient to operate its diesel for a period of seven days while the diesel generator is supplying maximum post-LOCA load demand. A day tank is also provided for each diesel, and is located in the Reactor Building. The day tank has a fuel capacity sufficient for approximately 8 hours of full-load operations. Low-level sensors on the day tank actuate dual motor-driven transfer pumps to replenish the day tank supply from the storage tank.

The standby AC power supplies are designed such that testing and inspection of equipment is possible during both normal and shutdown plant conditions.

Each standby AC power supply is composed of a three-phase synchronous generator and exciter, the diesel engine, the engine auxiliaries (including the fuel tanks), and the control panels. Figure 2.12.13 shows the emergency diesel generator system interconnections between the offsite power supplies and the diesel-generator standby AC power supplies for Divisions I, II, and III.

The transfer of each Class 1E bus to its standby power supply is automatic, should this become necessary, on loss of its offsite power. After the circuit breaker connecting the bus to the preferred power supply is open, large motors are kept on the bus for parallel coastdown and optimal residual voltage decay. When the voltage decays to an acceptable level, major loads are tripped from the Class 1E bus, except for the Class 1E 480V unit substation feeders. Then the diesel-generator breaker is closed when the required generator voltage and frequency are established. The large motor loads are later re-applied sequentially and automatically to the bus after closing of the diesel-generator breaker.

Each diesel generator is capable of being started or stopped manually from the main control room. Start/stop control and bus transfer control may be transferred to a local control station in the diesel generator room. Control room indications are provided for system parameters.

Each diesel generator, when operating other than in test mode, is independent of the preferred power supply. Additional interlocks to the LOCA and loss-of-power sensing circuits terminate parallel operation tests and cause the diesel generator to revert and reset to its automatic control system if either signal appears during a test. A lockout or maintenance mode removes the diesel generator from service. The inoperable status is indicated in the control room.

Devices monitor the conditions of the diesel generators and effect action in accordance with one of the following categories: (1) conditions to trip the diesel engine even under LOCA; (2) conditions to trip the diesel engine except under LOCA; (3) conditions to trip the generator breaker but not the diesel, and (4) conditions which are only annunciated.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.12.13 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the emergency diesel generators and their auxiliary systems.

Table 2.12.13: Emergency Diesel Generator System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The three diesel generator trains are mechanically and electrically independent.	1. Tests and verification inspection will be conducted which will include independent and coincident operation of the three trains to demonstrate complete divisional separation.	1. Plant tests and verification inspection for physical location confirm proper independence of three diesel generator divisions.
2. All components essential to the operation of the diesel generators are Seismic Category I and qualified for the appropriate environment for locations where installed.	2. See Generic Equipment Qualification verification activities (ITA).	2. See Generic Equipment Qualification Acceptance Criteria (AC).
3. The three diesel generators are capable of supplying sufficient AC power to achieve safe shutdown of the plant and/or to mitigate the consequences of a LOCA in the event of a coincident loss of normal power (Figure 2.12.13.).	3a. Confirmatory inspection will be performed to assure the maximum design loads expected to occur for each division are within the ratings of the corresponding diesel generator.	3a. The maximum loads expected to occur for each division (according to nameplate ratings) shall not exceed 90% of the rated power output of the diesel generator.
	3b. Testing will be conducted by synchronizing each diesel generator to the plant offsite power system and increasing its output power level to its fully rated load condition.	3b. Each of the three units shall produce rated power output at ≥0.8 PF for a period of ≥24 hours (momentary transients excepted). Each unit will then experience full load rejection by tripping the load and verifying the unit does not trip.
4. Each diesel generator is rated at 6.9 kV, three phase, 60 Hz; and is capable of attaining rated frequency and voltage within 20 seconds after receipt of a start signal.	4. Perform a test of each diesel generator to confirm its ability to attain rated frequency and voltage.	4. Each diesel generator attains a voltage of 6.9 kV±10%, and a frequency of 60 Hz±2% within 20 seconds after application of a start signal.

Table 2.12.13: Emergency Diesel Generator System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. In the event of a loss of normal power, each diesel generator unit is capable of starting (both manually and automatically), accelerating, and supplying its loads in the proper sequence and timing specified in the plant design documents. It is also capable of recovery following trip and restart of its largest load.	5. The automatic and manual start sequences will be tested for each diesel generator unit.	5. Each of the three units starts from each automatic and remote manual signal, then accelerates and properly sequences its loads. Each local manual signal also starts the corresponding unit, but does not initiate load sequencing. The automatic load sequence begins at ≤20 seconds and ends ≤65 seconds. Following application of each load, the bus voltage will not drop more than 25% measured at the bus. Frequency shall be restored to within 2% of nominal, and voltage shall be restored to within 10% of nominal within 60% of each load-sequence time interval. In addition, the unit's largest motor load shall be tripped and restarted after the unit has completed its sequence, and the bus voltage shall recover to 6.9 kV±10% at 60±2% Hz within 10 seconds.
6. Each diesel generator unit is capable of manually starting without the need for external electrical power. The air receiver tanks have sufficient capacity for five starts without recharging.	6. Each unit will be tested and the air receiver tank capacities shall be analyzed to assure its black-start capability is functional.	6. Black-start capability is demonstrated following one successful manual start, acceleration, and bus energization for each of the three units without assist from any external electric power. Following black start, each unit's receiver tanks shall have sufficient air remaining for four more starts.
7. Interlocks to the LOCA and loss-of-power sensing circuits terminate parallel operation tests and cause the diesel generator to revert and reset to its automatic control system if either signal appears during a test.	7. Interlocks for the standby AC power system will be tested.	7. While in a parallel test mode, each unit will revert and reset to its automatic control system following individual application of a simulated LOCA signal and a simulated loss-of-power signal.

Table 2.12.13: Emergency Diesel Generator System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8. Devices monitor the conditions of the diesel generators, and effect action in accordance with one of the following categories: (1) conditions to trip the diesel engine even under LOCA, (2) conditions to trip the diesel engine except under LOCA, (3) conditions to trip the generator breaker but not the diesel, and (4) conditions which are only annunciated.	8. Using simulated signals, protective interlocks and annunciations will be tested to assure they perform their functions, in accordance with the four categorical conditions described.	8. Successful circuit testing will be confirmed for the individual diesel generator protective sensors according to the following: <u>Category 1 Sensors:</u> Annunciations and diesel engine trip signals will be confirmed in combination with a simulated LOCA signal. <u>Category 2 Sensors:</u> Annunciations and diesel engine trip signals will be confirmed without a LOCA, but trips will be bypassed when a simulated LOCA signal is present. <u>Category 3 Sensors:</u> Annunciations and generator circuit breaker trip signals will be confirmed. <u>Category 4 Sensors:</u> Annunciation signals will be confirmed.
9. Each diesel has its own 7-day fuel storage tank, and its own 8-hour capacity day tank which is replenished by the storage tank.	9a. Visual inspection and calculation of capacities for each tank shall be performed.	9a. Tank inspections and calculations confirm proper capacities of the storage and day tanks. These shall be sufficient for full-load operation of each respective diesel generator for 7 days, and 8 hours, respectively.
	9b. The fuel transfer system shall be tested.	9b. Transfer system operation for each division will be confirmed by actuating both pumps from the day tank level sensors and observing proper flow into the day tanks.

Table 2.12.13: Emergency Diesel Generator System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
10. The manufacturer has conducted reliability testing on the units.	10. The manufacturer's test documents shall be visually inspected.	10. Visual inspection of manufacturer's test documents confirms the required reliability testing has been performed, and that the diesel generator has passed the test requirements.
11. Control indications are provided for D/G system parameters.	11. Inspections will be performed to verify presence of control room indication for the D/G system.	11. The designated instrumentation is present in the control room.

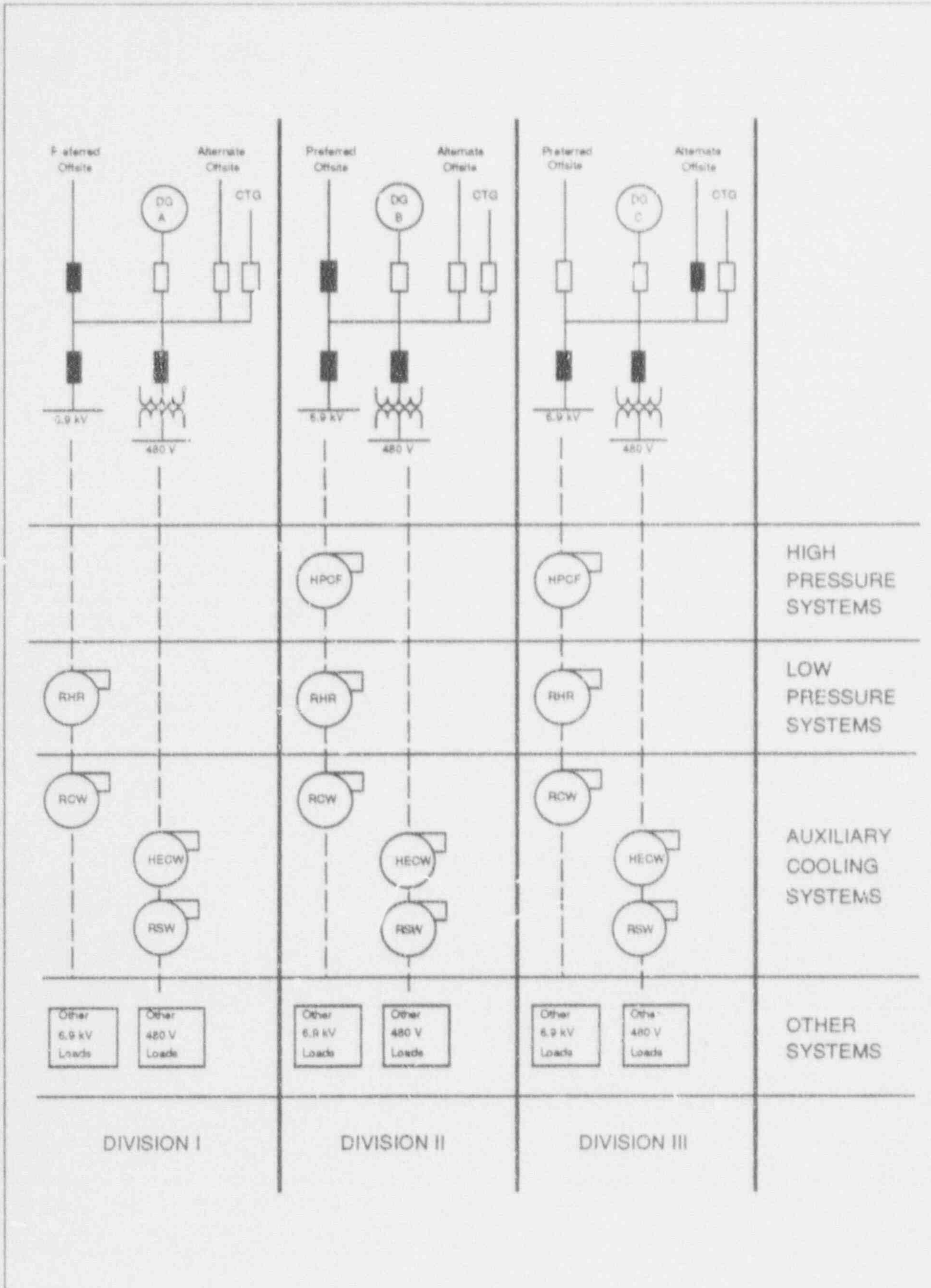


Figure 2.12.13 Emergency Diesel Generator System Interconnections

2.12.14 Reactor Protection System Alternate Current Power Supply

Not an ABWR system. No entry.

2.12.15 AC Power Supply And AC Instrument and Control Power Supply Systems

Design Description

Vital AC Power Supply System

The Vital AC Power Supply System as shown in Figure 2.12.15a is comprised of a Class 1E safety-related system, a non-Class 1E, non-safety-related system, and a non-Class 1E, non-safety-related computer system. Each system provides power to those "vital" instrument and control circuits for which continuity of power is desirable.

The safety-related Vital AC Power Supply System provides uninterruptable, regulated 120VAC power to the four divisions of the Class 1E Safety System Logic and Control (SSLC) System. Each of the four divisions contains its own constant voltage constant frequency (CVCF) static inverter power supply. Normal Power to each CVCF is supplied from a 480VAC Motor-Control Center (MCC) in the same division, except for the Division IV CVCF, which is supplied power from the Division I MCC. Backup Power for each CVCF is supplied from the 125VDC battery of the same division. Each CVCF output is provided to distribution panels local to the circuits powered. Divisional CVCFs and their respective distribution panels are electrically independent and physically separated between divisions and are appropriately identified. The Class 1E Vital AC Power Supplies and their distribution panels are located in Seismic Category I structures. Divisional CVCF power distribution is arranged such that the loss of a single CVCF power supply will not result in an inadvertent reactor shutdown.

The non-safety-related Vital AC Power Supply system provides uninterruptable, regulated 120VAC power to the non-safety-related logic and control circuits important to the continuity of power plant operation. There is a CVCF static inverter power supply in each of the three non-essential load groups. Normal Power to each CVCF is supplied from a 480VAC MCC in its associated load group. Each MCC receives power from the Plant Investment Protection (PIP) bus in the associated load group. Backup power to each CVCF is supplied from the non-essential 125VDC battery of the same load group. CVCF output is provided to distribution panels local to the circuits powered. Each load group CVCF and its respective distribution panels are electrically independent from the other load groups and are appropriately identified.

The non-safety-related Vital AC Computer Power Supply system provides uninterruptable, regulated 120VAC power to the non-safety-related plant computers. This system contains two non-essential CVCF static inverter power supplies. Normal Power to each CVCF is supplied from a different load group 480VAC Power center (P/C). Each P/C receives power from the PIP bus in its associated load group. Backup power to both CVCF power supplies is from the non-essential 250VDC battery. CVCF power output is provided to distribution panels local to the circuits powered. Each CVCF load group and its respective distribution panels are electrically independent from the other load groups and are appropriately identified.

Each CVCF contains an alternate power supply for maintenance of the inverter or to supply power in the event of inverter failure. The alternate power supply is a voltage-regulating stepdown transformer, which receives power from the same 480VAC power source as the normal power supply. Each inverter is synchronized in both frequency and phase with its alternate power supply to avoid unacceptable voltage spikes during transfer from the inverter to the alternate supply. Automatic transfer between the three CVCF power sources within a load group occurs as necessary to maintain a regulated output. Manual transfer between each CVCF power source is also provided.

AC Instrument and Control Power Supply System

The AC Instrument and Control Power System is shown in Figure 2.12.15b and is comprised of both a Class 1E safety-related system and a non-Class 1E, non-safety-related system. Both systems provide 120VAC power to "non-vital" instrument and control power loads which can sustain a power interruption during a loss of offsite power (LOOP) event.

The Class 1E safety-related AC Instrument and Control Power Supply system is comprised of a transformer and distribution panels in each of the three safety-related divisions. Each transformer is supplied power from a 480VAC MCC within its division and provides power to distribution panels local to the circuits powered. The transformers and distribution panels within each division are electrically independent and physically separated from each other and are appropriately identified. The Class 1E power supply system components are located in Seismic Category I structures.

The non-Class 1E, non-safety-related AC Instrument and Control Power Supply system is comprised of a transformer and distribution panels local to the circuits powered. The transformer is supplied power from either of two 480VAC MCCs through a manual transfer switch. Each MCC is powered from a different non-essential load group PIP bus.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.12.15 provides a definition of the inspections, tests and/or analyses, together with associated acceptance criteria which will be undertaken for the Vital AC Power Supply System and Instrument and Control Power Supply System.

Table 2.12.15: Vital AC Power Supply and AC Instrument and Control Power Supply Systems

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. A Class 1E Vital AC Constant Voltage Constant Frequency (CVCF) Power Supply and associated distribution panels are provided in each of the four Instrument and Control Safety Divisions. The CVCFs and associated distribution panels are located in Seismic Category I structures, identified, and electrically independent and physically separated from each other.	1. Inspections will be performed to confirm that the four Class 1E CVCFs and their associated distribution panels are located in Seismic Category I structures, identified, and that each division is electrically independent and physically separated from the other divisions.	1. Each of the four divisional Class 1E CVCFs and associated distribution panels are located in Seismic Category I structures, identified, and electrically independent and physically separated.
2. Each Class 1E CVCF receives power from the MCC and 125VDC battery in the same division, except Division IV, which is supplied AC power from the same division that provides the battery charger for the Division IV battery.	2. Inspections will be performed to confirm that the AC and DC power sources for each Class 1E CVCF is from its associated division, except the CVCF in Division IV which is supplied AC power from the same division that provides the battery charger for the Division IV battery.	2. Each Class 1E CVCF receives power from the MCC and 125VDC battery in the same division, except the CVCF in Division IV which is supplied AC power from the same division that provides the battery charger for the Division IV battery.
3. Each Class 1E CVCF inverter provides a 120VAC regulated voltage and frequency output and its alternate power supply within the same division provides a regulated voltage output. The CVCF automatically transfers between power sources within the same division to maintain the required output. Manual transfer is also provided	3. Inspections and tests will be conducted to confirm the automatic transfer within the same division and output regulation of the Class 1E CVCFs. Manual transfer will be tested.	3. Each Class 1E CVCF provides the required output regulation during normal operation, automatic and manual transfer operations.
4. A non-Class 1E Vital AC Constant Voltage Constant Frequency (CVCF) Power Supply and associated distribution panels are provided in each of the three non-essential load groups for Instruments and Controls important to the continuity of power plant operation. The CVCFs and associated distribution panels are identified and electrically independent from each other.	4. Inspections will be performed to confirm that the three non-Class 1E CVCFs and their associated distribution panels are identified and are electrically independent from each other.	4. Each of the three non-Class 1E CVCFs and associated distribution panels are identified and electrically independent from each other.

Table 2.12.15: Vital AC Power Supply and AC Instrument and Control Power Supply Systems (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. Each non-Class 1E CVCF receives power from the MCC and 125VDC battery in the same load group.	5. Inspections will be performed to confirm that the AC and DC power sources for each non-Class 1E CVCF is from its associated non-essential load group.	5. Each non-Class 1E CVCF receives power from the MCC and 125VDC battery in the same non-essential load group.
6. Each non Class 1E CVCF inverter provides a 120VAC regulated voltage and frequency output and its alternate power supply provides a regulated voltage output. The CVCF automatically transfers between power sources to maintain the required output. Manual transfer is also provided.	6. Inspections and tests will be conducted to confirm the automatic transfer and output regulation of the non-Class 1E CVCFs. Manual transfer will be tested.	6. Each non-Class 1E CVCF provides the required output regulation during normal operation, automatic and manual transfer operations.
7. Two non-Class 1E Vital AC Constant Voltage Constant Frequency (CVCF) Power Supplies and associated distribution panels are provided for the non-essential plant computers. The CVCFs and associated distribution panels are identified and electrically independent from each other.	7. Inspections will be performed to confirm that the two non-Class 1E computer CVCFs and their associated distribution panels are identified and are electrically independent from each other.	7. Each of the two non-Class 1E computer CVCFs and associated distribution panels are identified and electrically independent from each other.
8. Each non-Class 1E computer CVCF receives power from the P/C in the same load group and from the non-essential 250VDC battery.	8. Inspections will be performed to confirm that the AC power sources for each non-Class 1E computer CVCF is from its associated non-essential load group and from the non-essential 250VDC battery.	8. Each non-Class 1E computer CVCF receives power from the P/C in the same non-essential load group and from the non-essential 250VDC battery.
9. Each non-Class 1E computer CVCF inverter provides a 120VAC regulated voltage and frequency output and its alternate power supply provides a regulated voltage output. The CVCF automatically transfers between power sources to maintain the required output. Manual transfer is also provided. (See Figure 2.12.15a.)	9. Inspections and tests will be conducted to confirm the automatic transfer and output regulation of the non-Class 1E computer CVCFs. Manual transfer will be tested.	9. Each non-Class 1E computer CVCF provides the required output regulation during normal operation, automatic and manual transfer operations.

Table 2.12.15: Vital AC Power Supply and AC Instrument and Control Power Supply Systems (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
10. Three Class 1E 120VAC Instrument and Control Power Supplies and associated distribution panels are provided for the "non-vital" essential safety-related instrument and control circuits which can sustain a power interruption on loss of offsite power (LOOP). The Instrument and Control Power Supplies and associated distribution panels are located in Seismic Category I structures, identified, and electrically independent and physically separated from each other.	10. Inspections will be performed to confirm that the three Class 1E Instrument and Control Power supplies and their associated distribution panels are located in Seismic Category I structures, identified, and are electrically independent and physically separated from each other.	10. Each of the three Class 1E Instrument and Control Power Supplies and associated distribution panels are located in Seismic Category I structures, identified, and electrically independent and physically separated from each other.
11. Each Class 1E Instrument and Control Power Supply receives power from the MCC in the same division.	11. Inspections will be performed to confirm that the power sources for each Class 1E Instrument and Control Power Supply is from the MCC of the same safety division and that the transformer ratio provides a nominal 120VAC output.	11. Each Class 1E Instrument and Control Power Supply receives power only from the MCC in the same safety division and the transformer ratio provides a nominal 120VAC output.
12. The non-Class 1E 120VAC Instrument and Control Power Supply and associated distribution panels is provided for the "non-vital", nonessential instrument and control circuits which can sustain a power interruption a LOOP. The Power Supply receives input power from either of two 480VAC non-essential MCCs through a manual transfer switch. The MCCs are powered from Plant Investment Protection (PIP) buses in separate load groups. (See Figure 2.12.15b.)	12. Inspections and test will be conducted to confirm that the two power sources for the non-Class 1E 120VAC Instrument and Control Power Supply are from separate load groups and that the manual transfer switch will transfer power between sources.	12. The non-Class 1E 120VAC Instrument and Control Power Supply is powered from two MCCs in different non-essential load groups and the manual transfers power between the two power sources.

Table 2.12.15: Vital AC Power Supply and AC Instrument and Control Power Supply Systems (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
13. Each Vital AC Power Supply and AC Instrument and Control Power Supply is sized to supply the full load requirements of its connected loads.	13. Inspections will be performed to confirm that each Vital AC Power Supply and AC Instrument and Control Power Supply is sized (as determined by the nameplate rating) to supply the full load requirements of its connected loads.	13. Each Vital AC Power Supply and AC Instrument and Control Power Supply is sized (as determined by the nameplate rating) to supply the full load requirements of its connected loads.

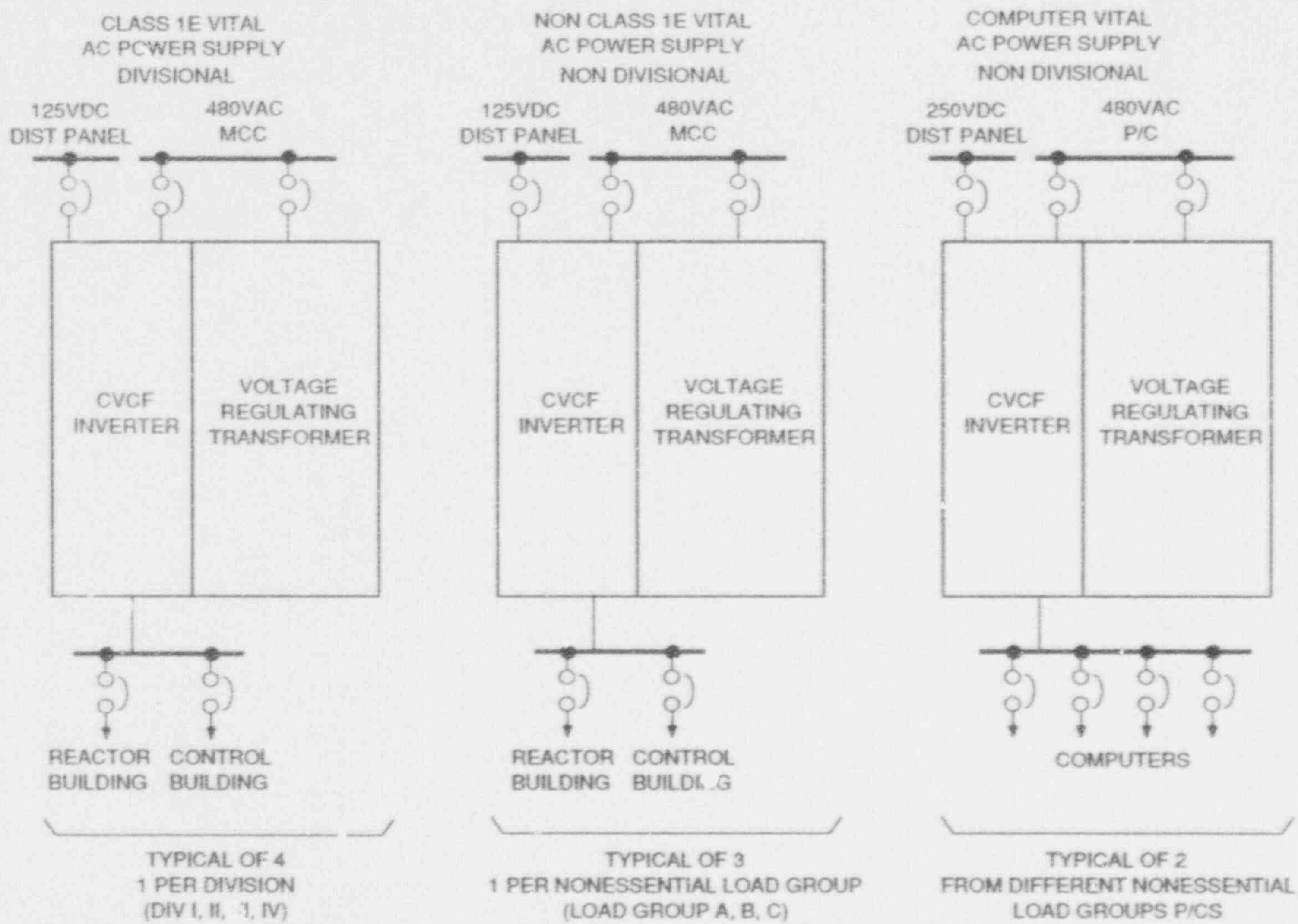


Figure 2.12.15a Vital AC Power Supply

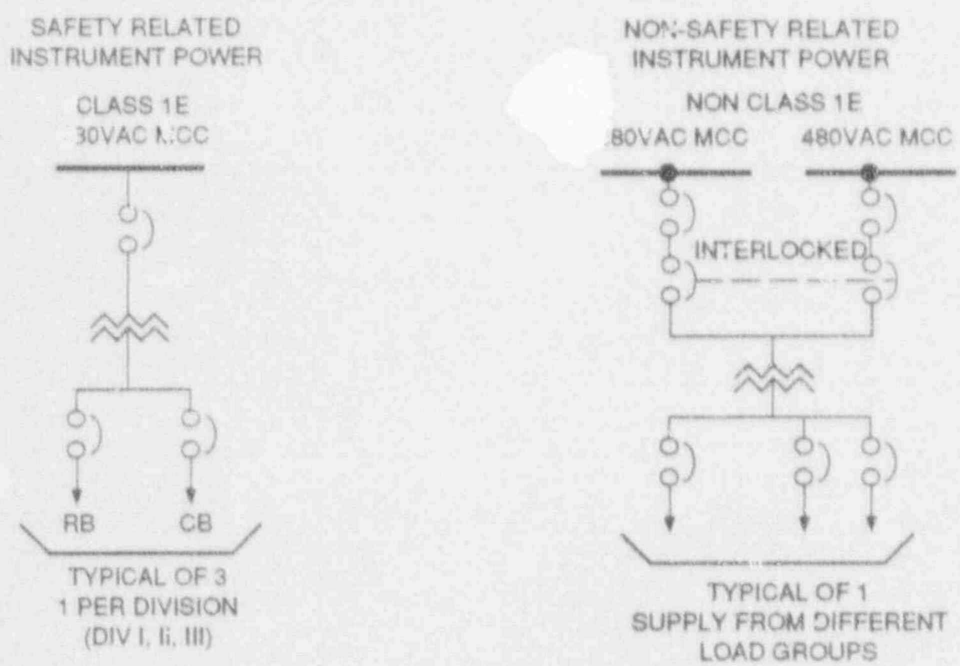


Figure 2.12.15b AC Instrument and Control Power

2.12.16 Instrument and Control Power Supply

No entry. Covered under Item 2.12.15.

2.12.18 Lighting and Servicing Power Supply Systems

Design Description

The plant lighting system is comprised of four independent lighting systems. They are the Normal Lighting System, the Standby Lighting System, the Emergency Lighting System, and the Guide Lamp Lighting System. The Normal Lighting system is non-Class 1E. The other three lighting systems are comprised of both safety-related and non-safety-related subsystems.

The Normal Lighting System is AC and non-essential and provides up to 50% of the lighting needed for operation, inspection, and repairs during normal plant operation and is installed throughout the plant in non-essential equipment areas, except for the passageways and stairwells. Normal Lighting is generally supplied from the non-essential Power Generation (PG) buses. In the non-essential equipment areas, the Normal Lighting is supplemented (a minimum of 50%) by the non-safety-related Standby Lighting System. Lighting from a single load group is acceptable for localized high intensity lighting and lighting in small rooms where only a limited number of fixtures are needed. Non-essential service outlets and internal lighting for non-essential panels is provided by the Normal Lighting system. In passageways and stairwells leading to non-essential equipment areas, the lighting is supplied from two different load groups of the non-safety-related standby Lighting System. With this configuration, non-essential equipment areas receive 100% of their lighting from two different power sources.

The non-safety-related AC Standby Lighting System is comprised of lighting from three non-essential load groups. Each load group is supplied from a different Plant Investment Protection (PIP) bus which is connectable to the non-essential Standby Power Supply (Combustion Turbine Generator (CTG)). The non-safety-related Standby Lighting System supplies a minimum of 50% of the lighting needs of the non-essential equipment areas and 100% of the lighting in passageways and stairwells leading to non-essential equipment areas (as described above). In addition, the non-safety-related Standby Lighting System supplies up to 50% of the lighting needs in essential equipment areas and in passageways and stairwells leading to essential equipment areas. The remainder of the lighting (a minimum of 50%) in the essential equipment areas and in passageways and stairwells leading to them is supplied from the safety-related Standby Lighting System. The non-safety-related Lighting in the essential equipment areas and the passageways and stairwells leading to them is supplied from the same non-essential load group as the essential load group (Safety Division) in the same area.

The safety-related AC Standby Lighting System is comprised of lighting from three essential Safety Divisions. Each of the three essential divisions is supplied power from the Class 1E divisional bus, which is connectable to the Space Emergency Diesel Generator (DG) of the essential Standby Power Supply in its respective division. Each safety-related Standby Lighting System supplies a minimum of 50% of the lighting needs of the essential equipment areas in its respective division and of the passageways and stairwells leading to its respective equipment areas. The essential lighting in the battery room and other Instrument and Control areas of Division IV is supplied from the safety-related Standby Lighting System of the same division as other divisional equipment supplying the areas (e.g., battery chargers). The Main Control Room lighting is supplied from the same two divisions of the safety-related Standby Lighting System as the divisions supplying the Main Control Room Heating, Ventilation, and Air Conditioning (HVAC). The remainder of the lighting (up to 50%) in the essential equipment areas and the passageways and stairwells leading to them is supplied from the non-safety-related Standby Lighting System in the same load group as the safety-related Lighting System. With this configuration, essential equipment areas receive 100% of their lighting needs from two different Standby Lighting power supplies.

The above described AC lighting configuration permits retaining approximately 50% of the lighting illumination in all passageways, stairwells and essential equipment areas during lighting maintenance or loss of a load group. Illumination from 50% of the lighting is adequate to observe equipment and support personnel movement. (See Figure 2.12.18a)

The Emergency Lighting Systems provide DC powere[illegible]p lighting to prevent total blackout in areas which are occupied or m[illegible]ccupied during periods when AC lighting is lost until the Normal or Standb[illegible] Lighting Systems are energized. The Emergency Lighting Systems, therebore, are not required to provide the same levels of illumination as the normal standby systems.

The non-safety-related Emergency Lighting System provides emergency lighting needs to the Radwaste Building control room (RWB), the Combustion Turbine Generator (CTG) area and control room, and the non-essential electrical equipment areas (both AC and DC). Lighting power for the RWB control room is supplied from the non-essential 250VDC battery. Lighting power for the non-essential electrical equipment rooms is supplied from the 125VDC battery in the same non-essential load group as the equipment in the room. Lighting power for the non-essential CTG is supplied from one of the non-essential 125VDC batteries.

The safety-related Emergency Lighting System provides the emergency lighting needs to the Main Control Room, the Remote Shutdown Panel room, the Emergency Diesel Generator areas and control rooms, and the essential electrical equipment rooms (both AC and DC). Lighting power for the identified essential areas is supplied from the 125VDC battery in the same divisions as the area. The lighting power to the Main Control Room is supplied from two 125VDC batteries in the same division as the safety-related Standby Lighting sources for the control room. (See Figure 2.12.18b.)

Guide Lamps are provided for stairways, exit routes, and major control areas such as the main control room, radwaste control room and remote shutdown panel areas. The guide lamps are self contained, battery pack units, suitable for operation in the environment of the areas in which they are located. The units contain a rechargeable battery with a minimum 8-hour capacity and a battery charger supplied from the Standby Lighting System of the area in which they are located. Guide Lamps are Seismic Category 1 and are Class 1E when located in safety-related areas.

All lighting systems are designed to provide lighting intensities consistent with the lighting needs of the areas in which they are located. The lighting design considers the effects of glare and shadows on control panels, video display devices, and other equipment, and the mirror effects on glass and pools. Lighting and other equipment maintenance, in addition to the safety of personnel, plant equipment, and operation is considered in the design. Areas containing flammable materials (e.g., battery rooms, fuel tanks, etc.) have explosion-proof lighting systems. Areas subject to high moisture have water-proof installations (e.g. drywell, wash-down areas). Plant AC lighting systems are generally of the fluorescent type with mercury lamps provided for high ceiling and yard lighting, except where breakage could introduce mercury into the reactor coolant system. Incandescent lamps are used for DC lighting systems and above the reactor, fuel pools, and other areas where lamp breakage could introduce mercury into the reactor coolant.

Lighting systems and their distribution panels and cables are identified according to their essentiality and type. Safety-related Llighting systems which are Class 1E, are located in Seismic Category I structures, and are electrically independent and physically separated. Cables are routed in their respective divisional raceways. Normal Lighting is separated from Standby Lighting. DC lighting cables are not routed with any other cables.

Plant Service buses supply power and heavy duty service outlets to equipment not generally used during normal plant power operation (e.g., turbine building and refueling floor cranes, welding equipment). Service outlets have grounded connections and the outlets in wet or moist areas are supplied from breakers with ground current detection.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.12.18 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the lighting and service power systems.

Table 2.12.18: Lighting and Service Power System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The AC lighting in non-essential equipment areas is supplied from two different lighting power sources. AC Normal Lighting supplies up to 50% of the lighting and non-safety-related AC Standby Lighting supplies the remainder of the lighting needs (a minimum of 50%). The lighting in passageways and stairwells to non-essential equipment areas is supplied from two non-safety-related Standby Lighting Systems from different non-essential load groups. High intensity lighting and lighting in small rooms may be from a single lighting system.	1. Inspections and tests will be conducted to confirm that two different AC lighting systems supply 100% of the lighting needs in non-essential equipment areas and in the passageways and stairwells leading to them, and at least 50% of the lighting is supplied from a Non-Safety- Related AC Standby Lighting System.	1. Two different AC lighting systems supply 100% of the lighting needs in the non-essential equipment areas and in the passageways and stairwells leading to them. At least 50% of the lighting is supplied by a non-safety-related AC Standby Lighting System. Localized high intensity lighting and lighting in small rooms is from a single source.
2. The AC lighting in essential equipment areas and the lighting in passageways and stairwells to essential equipment areas is supplied from two AC Standby Lighting Systems. AC safety-related Standby Lighting supplies a minimum of 50% of the lighting and non-safety-related AC Standby Lighting supplies the remainder of the lighting needs (up to 50%). Both the safety-related and the non-safety-related Standby Lighting Systems are in the same divisional or non-essential load group as the essential divisional area being supplied lighting.	2. Inspections and tests will be conducted to confirm that two different AC Standby Lighting Systems in the same load group supply 100% of the lighting needs in essential equipment areas and in the passageways and stairwells leading to them, and at least 50% of the lighting is supplied from the safety-related AC Standby Lighting System in the same division as the essential equipment area.	2. Two different AC Standby Lighting Systems in the same load group supply 100% of the lighting needs in the essential equipment areas and in the passageways and stairwells leading to them. At least 50% of the lighting is supplied by the safety-related AC Standby Lighting System in the same division as the essential equipment area.

Table 2.12.18: Lighting and Service Power System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3. The three non-safety-related AC Standby Lighting Systems are connectable to the Combustion Turbine Generator (CTG) and the three safety-related AC Standby Lighting Systems are connectable to their respective Emergency Diesel Generators (DG). Generally, the Normal Lighting system is supplied from the non-essential Power Generation (PG) buses (see Figure 2.12.18a).	3. Inspections will be performed to confirm that the three non-safety-related AC Standby Lighting Systems are connectable to the Combustion Turbine Generator (CTG) and that the three safety-related AC Standby Lighting Systems are connectable to their respective DG.	3. The three Non-Safety-Related AC Standby Lighting Systems can be supplied by the Combustion Turbine Generator (CTG) and that the three Safety-Related AC Standby Lighting Systems can be supplied by their respective DG.
4. The non-safety-related DC Emergency Lighting system supplies lighting, at reduced illumination levels, to non-essential areas which are occupied during periods when AC lighting is lost. These areas include the Radwaste Building (RWB) control room, the Combustion Turbine Generator (CTG) area and control room, and the non-essential AC and DC electrical equipment areas. The non-essential 250VDC battery supplies the DC lighting for the Radwaste Building and Combustion Turbine Generator. The lighting for the non-essential AC and DC electrical equipment areas is supplied from the non-essential 125VDC of the same load group as the equipment in the room.	4. Inspections and tests will be conducted to confirm that the non-essential 250VDC battery supplies DC Emergency Lighting to the Radwaste Building control room and Combustion Turbine Generator area and control room, and that the non-essential 125VDC batteries supply DC Emergency Lighting to the AC and DC non-essential electrical equipment areas in their respective load groups.	4. The non-essential 250VDC battery supplies DC Emergency lighting to the Radwaste Building control room. The non-essential 125VDC batteries supply DC Emergency lighting to the non-essential AC and DC electrical equipment areas in their respective load groups, the Combustion Turbine Generator area and control room. Lighting is supplied from a non-essential 125VDC battery.

Table 2.12.18: Lighting and Service Power System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. The safety-related DC Emergency Lighting system supplies lighting, at reduced illumination levels, to essential areas which are occupied during periods when AC lighting is lost. These areas include the Main Control room, the Emergency Diesel Generator areas and control rooms, and the essential AC and DC electrical equipment areas. Each essential 125VDC battery supplies the DC Emergency Lighting for the Emergency Diesel Generator area and control room, and the essential AC and DC electrical equipment area within its safety division. The Main Control room is supplied DC Emergency Lighting from the two essential 125VDC batteries in the same division as the Safety-Related Standby Lighting source for the control room. (See Figure 2.12.18b.)	5. Inspections and tests will be conducted to confirm that the essential 125VDC battery supplies DC Emergency Lighting to the Emergency Diesel Generator area and control room, and the essential AC and DC electrical equipment areas in the same safety division. Two essential 125VDC batteries, in the same division as the AC Standby Lighting Systems, supply DC Emergency Lighting to the Main Control Room.	5. An essential 125VDC battery supplies DC Emergency Lighting to the Emergency Diesel Generator area and control room, and the essential AC and DC electrical equipment areas in the same safety division. Two essential 125VDC batteries, in the same divisions as the AC Standby Lighting Systems, supply DC Emergency Lighting to the Main Control Room.
6. Guide Lamps are provided for stairways, exit routes, and major control areas, such as the Main Control room and the Radwaste Building Control room. They are self contained units with a minimum 8-hour battery pack and a battery charger supplied from the AC Standby Lighting System in the same area in which they are located. Guide Lamps are qualified Seismic Category I and are Class 1E when located in a safety-related area.	6. Inspections and tests will be conducted to confirm that Guide Lamps are located in stairways, exit routes, and major control areas and that they contain 8-hour batteries, rechargeable from the AC Standby Lighting System in the same area. Seismic Category I and, when in safety-related areas, Class 1E status will also be confirmed.	6. Guide Lamps are located in stairways, exit routes, and major control areas and contain 8-hour batteries, rechargeable from the AC Standby Lighting System in the same area. They are qualified Seismic Category I and are Class 1E in safety-related areas.

Table 2.12.18: Lighting and Service Power System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. All lighting systems are designed to provide the lighting intensities consistent with the lighting needs of the area and the intended purpose of the lighting system. The effects of the lighting, such as glare and shadows on equipment, and the mirror effects on glass and pools, are considered in the design. Lighting and other equipment maintenance, in addition to environmental conditions (e.g., areas containing flammable materials, wet or moist areas, areas above the reactor and fuel pools) are considered in the selection and installation of lighting equipment.	7. Inspection and tests will be conducted to confirm that lighting intensities are consistent with the lighting needs of the area and intended purpose of the lighting system. Inspection of the selected lighting equipment and its installation will be performed to confirm that it satisfies the requirements of its intended application.	7. The lighting intensities are consistent with the lighting needs of the area and intended purpose of the lighting system. Selected lighting equipment as installed satisfies the requirements of its intended application.
8. Lighting equipment, including distribution panels and cables, are identified according to essentiality and type. Safety-related lighting systems are Class 1E, electrically independent and physically separated, and are located in Seismic Category I structures. Cables are routed in the respective divisional raceways. Normal Lighting is separated from Standby Lighting. DC lighting cables are not routed with any other cables.	8. Inspections will be performed to confirm that lighting equipment and cables are identified, electrically independent, and physically separated between safety divisions and between the Normal and Standby Lighting Systems. The location of Class 1E equipment and cables in Seismic Category I structures and the separation between AC and DC cables will also be confirmed.	8. Lighting equipment and cables are identified, electrically independent, and physically separated between safety divisions and between the Normal and Standby Lighting Systems. Class 1E equipment and cables are located in Seismic Category I structures and DC cables are routed separate from ac cables.
9. Heavy duty service outlets (e.g., welding outlets) are supplied from plant services buses and have grounded connections. Service outlets in wet or moist areas are supplied from breakers with ground fault detection.	9. Inspections will be performed to confirm that heavy duty service outlets are supplied from plant service buses and have grounded connections, and that outlets in wet or moist areas are supplied from breakers with ground fault protection.	9. Heavy duty service outlets are supplied from plant service buses and have grounded connections. Outlets in wet or moist areas are supplied from breakers with ground fault detection.

2.13 Power Transmission

2.13.2 Reserve Auxiliary Transformer

No entry. Covered by item 2.12.1.

2.14.1 Primary Containment System

Design Description

The primary containment system incorporates the drywell and pressure suppression features of operating BWR plants and consists of a steel lined reinforced concrete containment structure fulfilling its design basis as a fission product barrier even at the increased pressure associated with a main steam pipe rupture or a break in the largest fluid pipe.

Main features include the upper and lower drywell containment surrounding the reactor pressure vessel, a wetwell with a water filled suppression pool serving as a heat sink during normal, and abnormal operations and accidents. Refer to Figure 2.14.1 Primary Containment System.

The primary containment volume is 259,563 cubic feet and is constructed as a right cylinder with an inside radius of 47' 7" and a reinforced concrete wall thickness of 6' 7" set on a reinforced concrete base mat 18' 0" thick and a wall height of 96' 9" measured between the top of the base mat and the underside of the containment top slab. The primary containment top slab is 7' 2" thick except beneath the fuel pool, steam dryer/separator pool, and around the drywell head opening where the slab is 7' 11" thick. The drywell head opening is enclosed with a steel head removable for refueling operations. The drywell design conditions are 45 psig and 340 degrees F. The wetwell design conditions are 45 psig and 219 degrees F.

The drywell is comprised of two volumes: an upper drywell volume of 193,878 cubic feet, surrounding the reactor pressure vessel and housing the steam and feedwater piping, the safety/relief valves, main steam drain piping and upper drywell coolers; and a lower drywell volume of 65,685 cubic feet, below the reactor pressure vessel housing the control rod drives, fine motion control rod drives, recirculation internal pumps, reactor cooling water heat exchangers, neutron monitoring system, equipment platform, lower drywell coolers and two drywell sumps.

The wetwell volume is 338,315 cubic feet, comprised of the suppression pool volume of 127,840 cubic feet at high water level or 126,427 cubic feet at low water level. The suppression chamber air space volume is 210,475 cubic feet at high water level and serves as the LOCA blowdown reservoir for the upper and lower drywell nitrogen and noncondensables which pass through the ten 48 inch diameter drywell to wetwell vertical vents connecting with thirty 2.3 feet diameter, 60 inch long horizontal vents with a total flow area of 125 square feet located at three levels below the suppression pool surface. The vent centerline submergence is 11.48 feet for the top row of horizontal vents, 15.98 feet for the center row of horizontal vents and 20.48 feet for the bottom row of horizontal vents. The suppression pool water serves as the heat sink to condense steam released into the drywell during a LOCA, or steam from safety relief valve activity or exhaust steam from reactor core injection coolant steam turbine operation. The 3' 11" thick drywell diaphragm floor has steel liners on both top and bottom sides to minimize bypass leakage.

Access to the upper drywell is provided through a double sealed personnel lock and an equipment hatch. The lower drywell access is provided through a personnel access tunnel with a double sealed personnel lock at the reactor building end. An equipment transfer tunnel is sealed by an equipment hatch removable only during refueling or maintenance outages. These access tunnels span the suppression chamber. Access to the suppression chamber is provided by a hatch located in the reactor building.

Prior to reactor operation the atmospheric control system in conjunction with the HVAC primary containment purge system and the drywell cooling fans establish an inert gas environment in the primary containment with nitrogen to limit the oxygen concentration to preclude combustion of hydrogen released during a LOCA. The primary containment leak rate must be less than 0.5% per day based on a 39 psig post accident pressure. The primary containment design pressure is 45 psig. Additional nitrogen gas is added to the drywell and the wetwell to maintain a positive pressure and prevent air inleakage. High pressure nitrogen is also used for pneumatic controls inside the primary containment to avoid adding air to the inert atmosphere.

Refer to Section 2.14.2 for data on the Containment Internal Structures and Section 2.14.3 for data on the Reactor Pressure Vessel Pedestal.

Design Bases

The pressure suppression containment structure has the capability to maintain its functional integrity during and following the peak transient pressures and temperatures caused by the worst LOCA pipe break postulated to occur simultaneously with loss of offsite power and a safe shutdown earthquake. The containment structure is designed to accommodate the full range of loading conditions associated with normal and abnormal operations including LOCA related design loads in and above the suppression pool including negative pressure differences between the drywell, wetwell and reactor building.

The containment structure has design features to withstand coincident fluid jet forces associated with outflow from the postulated rupture of any pipe within the primary containment.

The containment structure has design features to accommodate flooding to sufficient depth above active fuel to permit safe removal of fuel assemblies from the reactor core after a postulated design basis accident.

The containment structure is protected from and designed to withstand hypothetical missiles from sources within the primary containment and pipe whip due to the uncontrolled motion of broken pipes.

The containment structure is configured to channel flow from postulated pipe ruptures in the drywell to the pressure suppression pool designed with the required vent submergence and water volume to accommodated the energy of the fluid released.

The containment structure and penetration isolation system with concurrent operation of other accident mitigation systems, are designed to limit fission product leakage during and following a postulated design basis accident to values well below leakage calculated for allowable offsite doses. Leakage tests are described below.

The containment system has features for performing periodic leak rate tests at a reduced test pressure based on a 39 psig peak LOCA pressure initial leak test to establish primary containment leakage limit of 0.5% by weight per day of the primary containment free air volume. Type B tests measure local leakage, such as, individual air locks, hatches, drywell head, piping, electrical and instrument penetrations. Type C tests measure isolation valve leakage, and the Type A test measures the integrated containment leak rate. The individual and integrated preoperational leak rates are recorded in the plant technical specifications for comparison with the periodic leak rate test results. Periodic Type A integrated leak rate tests are conducted (three in a ten year period at nearly equal intervals with the third test at the ten year plant in-service inspection).

By-pass leakage between the drywell and the wetwell through the drywell diaphragm floor and the wetwell to drywell vacuum breakers is designed 0.05 square feet of area based on A over the square root of K, established by the preoperational test. The recorded value in the technical specifications is 0.005 square foot and is periodically tested and verified to be less than this rate and is conducted at a wetwell air chamber pressure that does not clear the drywell to wetwell vents.

A drywell to reactor vessel refueling bellows and reactor well platform are provided to seal off the drywell during refueling to enable the reactor well to be flooded prior to removal of the reactor steam separator and fuel bundle manipulations. Piping, cooling air ducts and return air vent openings in the reactor well platform must be removed, vents c[illegible] and sealed watertight before filling the reactor well with water. The refueling bellows also absorbs the movement of the vessel caused by operating temperature variations and seismic activity.

The primary containment isolation is accomplished with inboard and outboard isolation valves on each piping penetration which are signaled to close on detection of high drywell pressure or reactor low water level. Safety systems performing a post LOCA function are capable of opening their isolation valves as needed.

The drywell bleed system provides the means to reduce containment pressure following heat up of the drywell during reactor startup.

A containment vent system consisting of dual rupture disks in series are provided to relief containment overpressure and isolation valves are provided for reclosure of the containment.

The standby gas treatment system is connectable to the containment purge exhaust system in the event the containment contains airborne radioactivity requiring removal with the nitrogen inert gas atmosphere prior to personnel entry of the drywell and wetwell.

Drywell coolers are provided to remove heat released into the drywell atmosphere during normal reactor operations.

Drywell and wetwell sprays are provided to limit temperature and pressure following an accident within the primary containment.

The Flammability Control System provides redundant hydrogen recombiners to remove any hydrogen released into the primary containment during a LOCA.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.14.1 provides a definition of the inspection, test, and/or analyses together with the associated acceptance criteria which will be undertaken for the Primary Containment System.

Table 2.14.1: Primary Containment System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Primary Containment System is shown in Figure 2.14.1a.	1. Review the as-built Primary Containment System construction records and conduct onsite inspections to confirm the configuration is as shown in the design documents.	1. As-built Primary Containment System installations conform to the configuration for all components shown in Figure 2.14.1a.
2. Drywell free air volumes are: Upper Drywell: 5490 cubic meters. Lower Drywell: 1860 cubic meters. Drywell: 7350 cubic meters.	2. Verify from as-built documents the two independent drywell volumes less internal structures, piping, RPV and equipment (1220 cubic meters in upper drywell and 30 cubic meters in the lower drywell) are equal or less than the design free air volumes. The Upper Drywell is 29 M diameter, 9 M high from diaphragm floor to ceiling. Lower Drywell is 10.6 M diameter, 11.55 M from invert of RPV to top of basemat.	2. As-built documentation and calculations shall confirm the free air volumes of Upper and Lower Drywell are not more than the design values.
3. Wetwell volumes are: Suppression Pool: low water level 3580 cubic meters; high water level: 3620 cubic meters. Suppression Chamber: high water level 5960 cubic meters. Total Wetwell: 9580 cubic meters.	3. Verify from the as-built documents and calculations the Wetwell less internal structures, piping and equipment (50 cubic meters) is equal or more than the design free air volume. The minor diameter is 14 M, the major diameter is 29 M and the height from the basemat to the ceiling (underside of the diaphragm floor) is 7 M.	3. As-built documentation and calculations shall confirm the water volumes of the Suppression Pool and the free air volume of the Suppression Chamber are not less than the design values.
4. Suppression pool water drawdown volume due to holdup in the Lower Drywell is based on the Lower Drywell volume below the five return openings in the lower drywell wall connect into the drywell to wetwell vertical vents.	4. Measure and by visual inspection verify the five 0.3 m diameter return paths from the lower drywell are not installed higher than elevation (-)4550 mm through the wall into the vertical drywell to wetwell vents. Calculate the volume of water that could be contained below the five return paths.	4. Confirm the wetwell drawdown volume that can be contained in the lower drywell below the five return paths in the drywell to wetwell vertical vents is less than 815 cubic meters. Confirm the five vents are a minimum of 0.3 m diameter and connect to the drywell to wetwell vertical vents.

Table 2.14.1: Primary Containment System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. The configuration of the Drywell Head is shown in Figure 2.14.1b	5. Review documentation of the installed drywell head and associated equipment for compliance and (if applicable) the code stamp on the hardware.	5. Confirm the as-built configuration of the Drywell Head and associated equipment is designed, fabricated, installed and tested in compliance with applicable codes and regulatory requirements.
6. Two air lock type personnel access hatches and three equipment hatches are provided through the primary containment wall are shown in Figure 2.14.1b.	6. Review as-built documentation, operational test reports and by visual inspection of the installation and operation of two air lock type personnel access units and three equipment hatches determine compliance and the code stamp on the hardware.	6. Confirm the as-built personnel locks and equipment hatches are located as shown in Figure 2.14.1b and are designed, fabricated, installed and tested in compliance with applicable codes and regulatory requirements.
7. Primary containment leakage is minimized with drywell and wetwell liners anchored to all interior sides of primary containment perimeter walls, ceilings and floors. Wetted portions of suppression pool walls and floors are steel lined with stainless steel cladding. Both surfaces of the upper drywell diaphragm floor are lined, and the lower drywell floor is lined. The pedestal and reactor shield wall are constructed of steel with concrete fill. The drywell head and personnel locks and hatches are steel with double type testable seals.	7. Review as-built documentation, test reports and conduct visual inspection of all primary containment liner welds at joints, penetration sleeves and structural interfaces. Verify tests of seals at the drywell head, personnel locks and hatches.	7. Confirm that liners have been designed, fabricated, installed and leak tested.
8. Primary containment is designed as a Seismic Category I reinforced concrete structure.	8. Review as-built documentation to verify construction materials were tested to required standards, placed and installed as configured for the Seismic Category I requirements.	8. Confirm that primary containment reinforced concrete structure, materials, and appurtenances have been designed, fabricated, installed and tested in compliance with applicable codes and regulatory requirements.

Table 2.14.1: Primary Containment System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9. The primary containment integrated leak rate tests are designed to limit the leak rate to 0.5% per day at the primary containment 39 psig peak LOCA pressure.	9. Conduct the as-built Primary Containment System Type A, B and C primary containment leakage tests in conjunction with the preoperational high and reduced pressure leakage test reports to confirm the Type A integrated leak rate test results are within the limits recorded in the Technical Specifications.	9. Confirm the allowable leakage from the primary containment into the secondary containment does not exceed 0.5% per day with the containment peak LOCA pressure of 39 psig.
10. The Type B tests of welds in the primary containment liner, welds in sleeves, electrical and instrument cable penetrations and capped future penetrations are designed to detect excessive leakage and determine when repair is required.	10. Review the as-built Type B test leakage measurements and analyses the preoperational high and reduced pressure tests of the primary containment structural welds, liner welds; piping, electrical and instrument penetrations, sleeve welds; personnel locks, hatches, tunnels and drywell head welds to confirm their leak tight integrity.	10. Confirm the Type B tests have been conducted and the leakage results are within the required leakage limits recorded in the Technical Specifications.
11. The Type C tests for primary containment isolation valves, personnel entry lock seals, hatch seals and drywell head seals are designed to detect excessive leakage and determine when repairs are required.	11. Review the as-built Type C test measurement records and analyses the preoperational high and low pressure test records for isolation valves; personnel lock, hatch and drywell head seals to confirm their leak tight integrity. Verify the leakage limits are recorded in the Technical Specifications.	11. Confirm the Type C tests have been conducted and the leakage results are acceptable with the limits established during preoperational testing and recorded in the Technical Specifications.
12. Penetration sleeves, hatches and personnel locks are designed Safety Class 2, Quality Group B, Seismic Category I. Personnel lock instruments and controls are powered from the essential electric sources serving the Security System.	12. Verify from the as-built records of all penetrations, hatches and personnel locks their safety classification, seismic category and electric power source for this equipment.	12. Confirm all penetrations, the drywell head, personnel locks and equipment hatches are designed, fabricated, installed and tested in compliance with applicable codes and regulatory requirements.

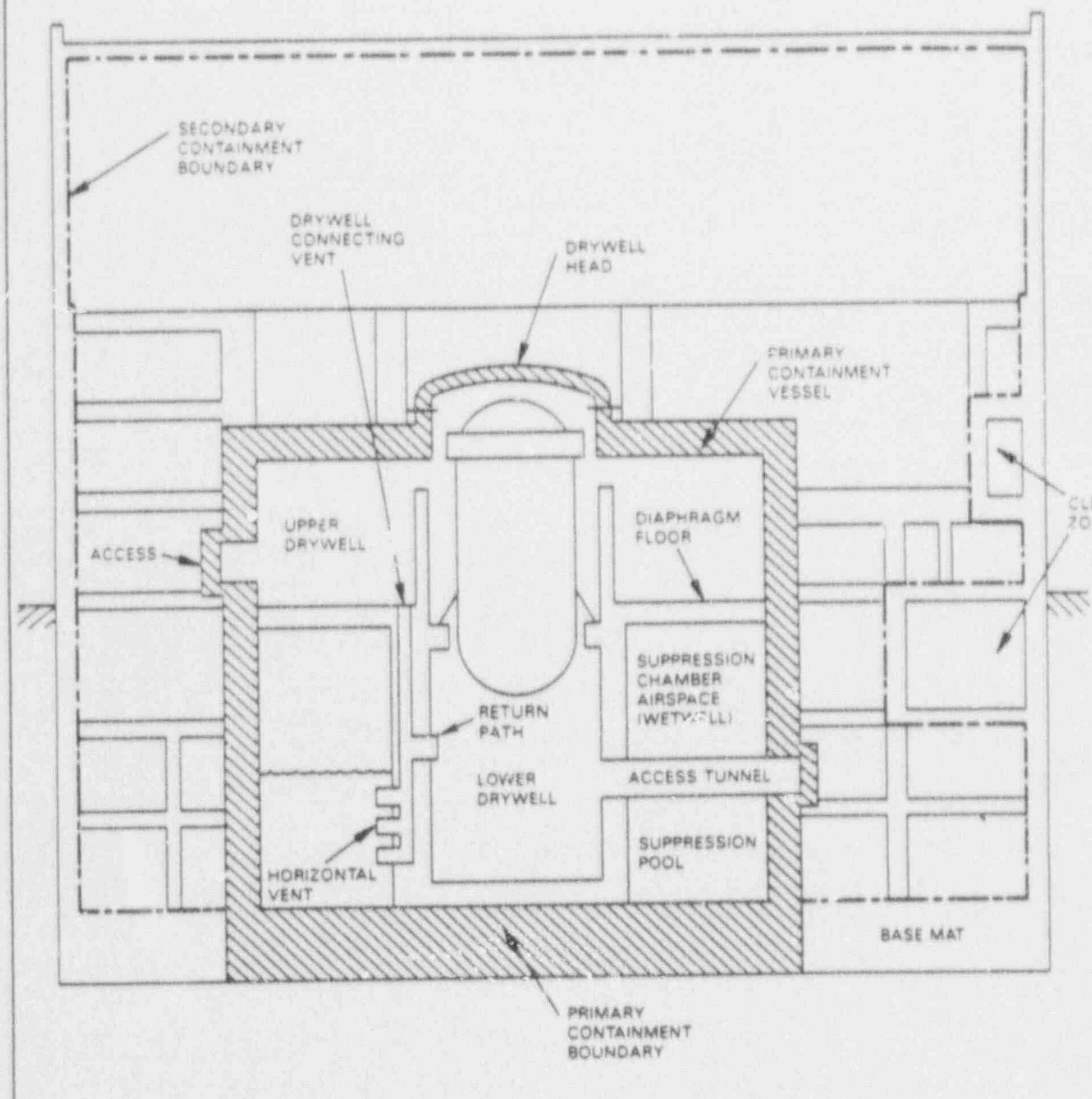


Figure 2.14.1 Primary Containment System

2.14.2 Containment Internal Structures

Design Description

The containment internal structures of the primary containment system consist of the reactor shield wall and vessel insulation support, drywell diaphragm floor over the wetwell, personnel and equipment access tunnels over the suppression pool, reactor vessel refueling bellows, reactor well platform, upper drywell piping support structure, safety relief valve hoist monorail, main steam isolation valve hoist monorail, reactor vessel stabilizers, undervessel restraint beam and lower drywell equipment platform. Refer to Figure 2.14.2a Reactor Building RCCV Internal Structures Nomenclature and Figure 2.14.2b Primary Containment Configuration.

Main features include:

The reactor shield wall surrounds the reactor pressure vessel to reduce neutron fluence and gamma shine on drywell equipment during reactor operation and protect personnel during reactor hot standby and shutdowns for maintenance and refueling. The RPV insulation is supported from the internal surface of the reactor shield wall. The reactor shield wall is supported on top of the pedestal wall.

The diaphragm floor supports the air plenums and cooling coil sections of the drywell cooling system and seals the penetrations for the discharge piping to the suppression pool from the safety relief valves.

The lower drywell internal support structures include the CRD housing restraint beam that carries the control rod drives and their hydraulic piping; fine motion control rod drives, incore monitors and their cabling; steel supports for the ten recirculation internal pumps and their RCW heat exchangers; circular equipment platform which rotates on a rail supported from internal pedestal columns; stairs, ladders, grating and lower drywell cooler air ducts.

The rotating equipment platform contains the RIP dual jacking screw gear motors that can be placed directly under the RIP to be removed. The equipment platform is rotated to place the removed RIP unit under the electric hoist where the auxiliary RIP cover is place over the pump and motor unit prior to laying the unit down on the dolly so it will pass through the equipment transfer tunnel to the RIP maintenance facility. CRD removal equipment is built into the equipment platform for loading onto the CRD dolly for transfer through the equipment tunnel to the CRD maintenance facility. Reverse procedures allow for reinstallation of the RIP units and the CRD units.

The wetwell internal structures support the two tunnels spanning the suppression pool for equipment transfer and personnel access. Supported above the suppression pool are the access grating, railings, stairs and monorail for servicing the eight drywell to wetwell vacuum breakers and various inboard isolation valves above the suppression pool. The suppression pool stainless steel clad liner is supported from the wetwell walls and floor. The 3' 11" thick drywell diaphragm floor has steel liners on both top and bottom sides to minimize bypass leakage. The safety relief valve discharge quenchers are supported from the floor of the suppression pool. Steel supports are also provided for the safety relief discharge pipes that pass through the drywell diaphragm floor and connect to the quenchers. Suction strainers connected to the RHR, HPCF, RCIC and SPCU piping are anchored to the suppression pool floor and walls.

The upper drywell piping and equipment support structure carries electric and instrument cable trays, drywell coolers, air distribution ductwork, steam and feedwater piping, main steam isolation valves and drain piping, safety/relief valves and their discharge piping. Monorails are suspended from the ceiling of the drywell for hoists to work on the valves. Support is provided for isolation valves and piping of the RHR, HPCF, RCIC, SLC, RWC, RCW and other systems in the drywell. This steel structure also supports access stairs, walkways, railings and gratings.

A drywell to reactor vessel refueling bellows and reactor well platform are provided to seal off the drywell during refueling to enable the reactor well to be flooded prior to removal of the reactor steam separator and fuel handling; piping, cooling air ducts and return air vent openings in the reactor well platform must be removed, vents closed and sealed watertight before filling the reactor well with water. The refueling bellows also absorbs the movement of the vessel caused by operating temperature variations and seismic activity.

Access to the lower drywell is provided through a personnel tunnel with a double sealed personnel lock at the reactor building end. An equipment access tunnel is sealed by a component hatch removable only during refueling or maintenance outages. These access tunnels span the suppression chamber. Access to the suppression chamber is provided by a hatch located in the reactor building.

The primary containment internal structures are designed to withstand coincident fluid jet forces associated with outflow from the postulated rupture of any pipe within the primary containment.

The primary containment internal structures are protected from and designed to withstand hypothetical missiles from sources within the primary containment and pipe whip due to the uncontrolled motion of broken pipes.

The primary containment drywell to wetwell vents are configured to channel flow from postulated pipe ruptures in the drywell to the pressure suppression pool. These internal structures are designed with the required vent submergence and water volume to accommodate the energy of the fluid released into the suppression pool.

Leakage between the wetwell and the drywell through the drywell diaphragm floor and the wetwell to drywell vacuum breakers is periodically tested and verified against the allowable values of the design, established by the preoperational test and recorded in the technical specifications.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.14.2 provides the definition of the inspection, tests and/or analyses together with the associated acceptance criteria which will be undertaken for the Containment Internal Structures.

Table 2.14.2: Containment Internal Structures

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Containment Internal Structures are shown in Figure 2.14.2a.	1. Review the as-built Containment Internal Structures construction records and conduct onsite inspections to confirm the configuration is as shown on the design documents.	1. As-built Containment Internal Structures installations conform to the configuration for all components shown in Figure 2.14.2a.
2. The lower drywell equipment platform is a circular structural steel assembly which can be rotated on a continuous support rail mounted on independent columns and beams. Special CRD and incore monitor handling equipment and RIP handling equipment are mounted on the platform.	2. Visually inspect the platform and verify that the CRD, incore monitoring and RIP equipment handling features are installed.	2. As-built functional tests and visual inspection shall confirm the equipment platform is able to accomplish both the CRD and incore monitor removal and installation tasks and both the RIP removal and installation tasks.
3. The RIP hoist and support beam is designed to tilt the RIP unit both from a horizontal position to a vertical position and vice versa. The hoist shall both install and remove the RIP protective cover.	3. Demonstrate and visually inspect the capability of the hoist to tilt the RIP unit from the horizontal to the vertical position and remove the RIP protective Cover. Also verify the capability to install the RIP cover and tilt the RIP unit from the vertical to the horizontal position and place the RIP unit on the dolly.	3. Confirm the Lower Drywell RIP hoist satisfies its design requirements.
4. The Lower Drywell restraint beam is designed to support the CRD housings, the FMCD units, the incore monitors, and stabilize the assembly during a seismic event.	4. Review documentation and visually inspect the installed restraint beam and associated structures to verify the CRD housings, FMCD units and the incore monitors are provided support.	4. Confirm the Lower Drywell restraint beam and the associated structures satisfy the design requirements for support of the CRD housings, FMCD units, and incore monitors.
5. The CRD hydraulic piping supports extending from the control rod drive housings to the primary containment penetrations are Safety Class 2, Quality Group B and Seismic Category I.	5. Review the as-built documentation for the CRD hydraulic piping supports and visually inspect the supports for seismic anchors and braces.	5. Confirm the CRD hydraulic piping supports are in their design locations and are designed, fabricated and installed in compliance with applicable codes and regulatory requirements.

Table 2.14.2: Containment Internal Structures (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. Ten RIP structural supports are designed Safety Class 2, Quality Group B and Seismic Category I to restrain the suspended motor end of the RIP units and provide an anchor and guide for the jacking screws used to lower and raise the unit from and to the RPV mounting flanges.	6. Review the as-built documentation of the RIP supports and visually inspect the installation for compliance and (if applicable) the code stamp on the hardware.	6. Confirm the as-built configuration of the RIP structural supports and verify they are designed, fabricated, installed and tested in compliance with applicable codes and regulatory requirements.
7. Ten RIP heat exchanger supports and associated cooling water piping supports are designed to Safety Class 3, Quality Group C, and Seismic Category I.	7. Review the as-built documentation of the RIP heat exchanger supports and the cooling water piping and visually inspect the installation for compliance and (if applicable) the code stamp on the hardware.	7. Confirm the as-built configuration of the and verify they are designed, fabricated, installed and tested in compliance with applicable codes and regulatory requirements.
8. The reactor pressure vessel skirt ring girder support is designed to anchor the reactor pressure vessel to the pedestal at the RPV skirt flange.	8. Review the reactor pressure vessel skirt ring girder support documentation and inspect the installation for compliance and (if applicable) the code stamp on the hardware.	8. Confirm the as-built configuration of the reactor pressure vessel skirt ring girder support and verify it is designed, fabricated, installed and tested in compliance with applicable codes and regulatory requirements.
9. The under vessel head insulation support extends from the inside surface of the vessel skirt, down between the RIP motors and the RIP heat exchangers and across the bottom of the reactor vessel bottom head.	9. Review the as-built records and inspect the reactor pressure vessel bottom head insulation support to verify their are no open joints in the insulation and the insulation is sealed at the CRD housings, incore monitors, and RWCU reactor drain piping.	9. Confirm the RPV bottom head insulation support is designed, fabricated and installed to hold the insulation in place with no opening of joints.
10. The reactor shield wall is a composite double walled steel cylinder with concrete fill supported on top of the drywell pedestal. The reactor shield wall surrounds the reactor and has an internal diameter of 9440 mm, an outside diameter of 10,600 mm and a thickness of 580 mm. The shield wall is designed Safety Class 2, Quality Group B and Seismic Category I.	10. Review the as-built records and inspect the reactor shield wall placement and uniformity of the annulus space for RPV inspections.	10. Confirm the reactor shield wall is designed, fabricated, and installed to meet the Safety Class 2, Quality Group B and Seismic Category I requirements.

Table 2.14.2: Containment Internal Structures (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
11. The diaphragm floor is a 1200 mm thick reinforced concrete structure with steel liners on both top and bottom surfaces. The diaphragm floor is designed to Safety Class 2, Quality Group B and Seismic Category I. This floor separates the wetwell from the drywell and is designed to accommodate a differential pressure of 25 psid with a leak rate limited to 10% of the drywell free air volume over a 24-hour period.	11. Review the as-built construction and test records to verify the design requirements have been met. Visually inspect the floor and ceiling liners and penetrations.	11. Confirm the diaphragm floor is designed and constructed to meet the differential pressure and leakage limits and comply with the code and regulatory requirements.
12. Upper Drywell piping support structure is designed Safety Class 3, Quality Group C and Seismic Category I to support, anchor and guide safety related piping, and provide pipe whip restraints to protect this piping.	12 Review as-built documentation of the installed piping support structure against the design documentation and inspect the piping support structure and its ties to the reactor shield wall and the upper drywell wall. Verify the pipe restraints are in place.	12. Confirm the piping support structure is designed, fabricated, and installed in compliance with applicable codes and regulatory requirements.
13. A system of monorails is provided from the ceiling of the upper drywell to allow removal and reinstallation of the inboard main steam isolation valves, the safety relief valves and miscellaneous valves, and equipment located within the upper drywell.	13. Review the as-built documentation for the monorails and inspect the upper drywell for placement to verify a means is available for equipment removal and replacement.	13. Confirm the monorail system is designed, fabricated, installed and tested to verify the required load capacity has been provided.

1. DRYWELL HEAD
2. RCCV WALL
3. DRYWELL HEAD FLANGE
4. RPV STABILIZER
5. PENETRATION
6. STABILIZER TRUSS
7. VERTICAL CHANNELS
8. LINER PLATE
9. SUPPRESSION CHAMBER ACCESS HATCH
10. DIAPHRAGM FLOOR (D/F)
11. REACTOR SHIELD WALL
12. U/D EQUIPMENT HATCH
13. U/D PERSONNEL LOCK
14. DRYWELL CONNECTING VENTS
15. LOWER DRYWELL (L/D)
16. UPPER DRYWELL (U/D)
17. REACTOR PRESSURE VESSEL
18. SUPPRESSION CHAMBER AIRSPACE
19. EQUIPMENT PLATFORM
20. L/D EQUIPMENT TUNNEL AND HATCH
21. L/D PERSONNEL TUNNEL AND LOCK
22. SUPPRESSION POOL
23. RPV SKIRT
24. RPV SUPPORT BRACKET
25. RPV PEDESTAL
26. SRVDL QUENCHER
27. QUENCHER SUPPORT
28. HORIZONTAL VENT
29. BOTTOM LINER PLATE
30. L/D SEAL PLATE
31. RETURN LINE
32. RCCV TOP SLAB
33. BASEMAT
34. REACTOR WELL
35. REFUELING SEAL

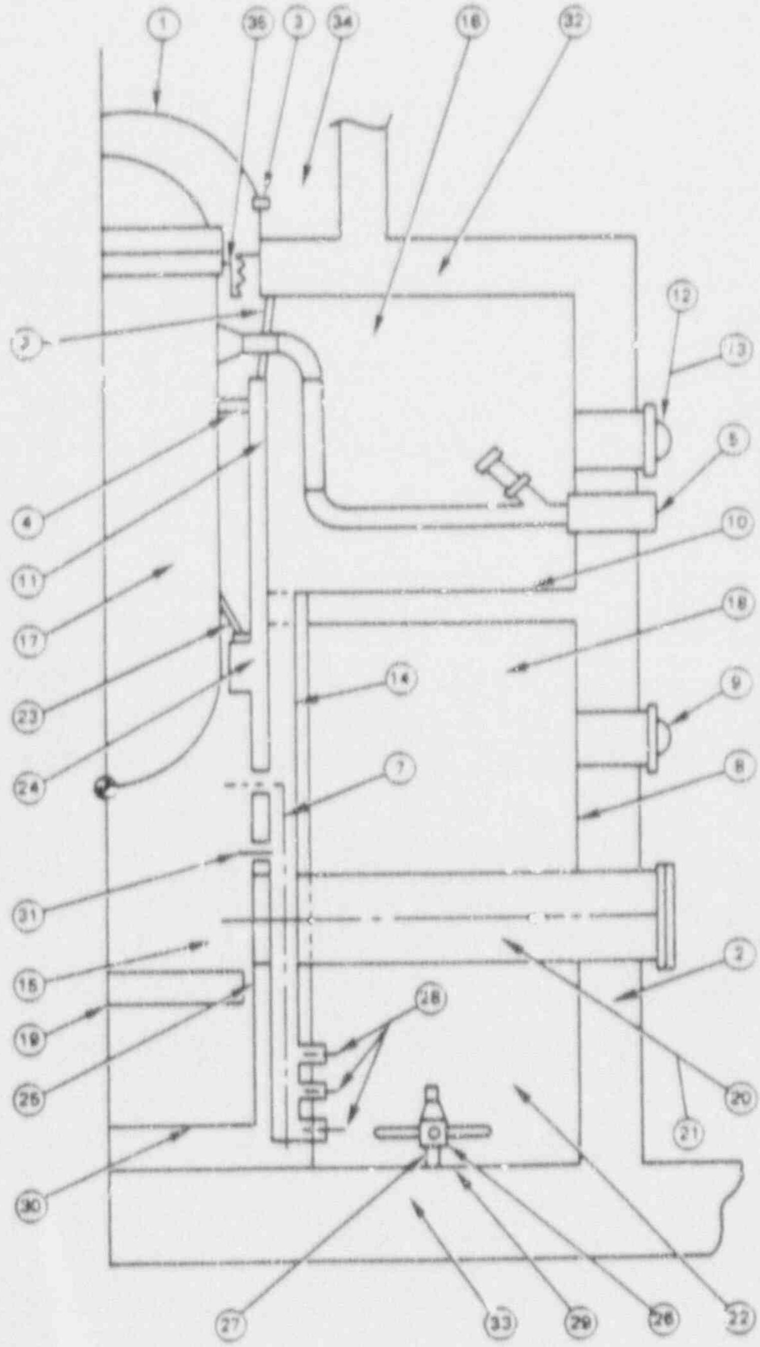
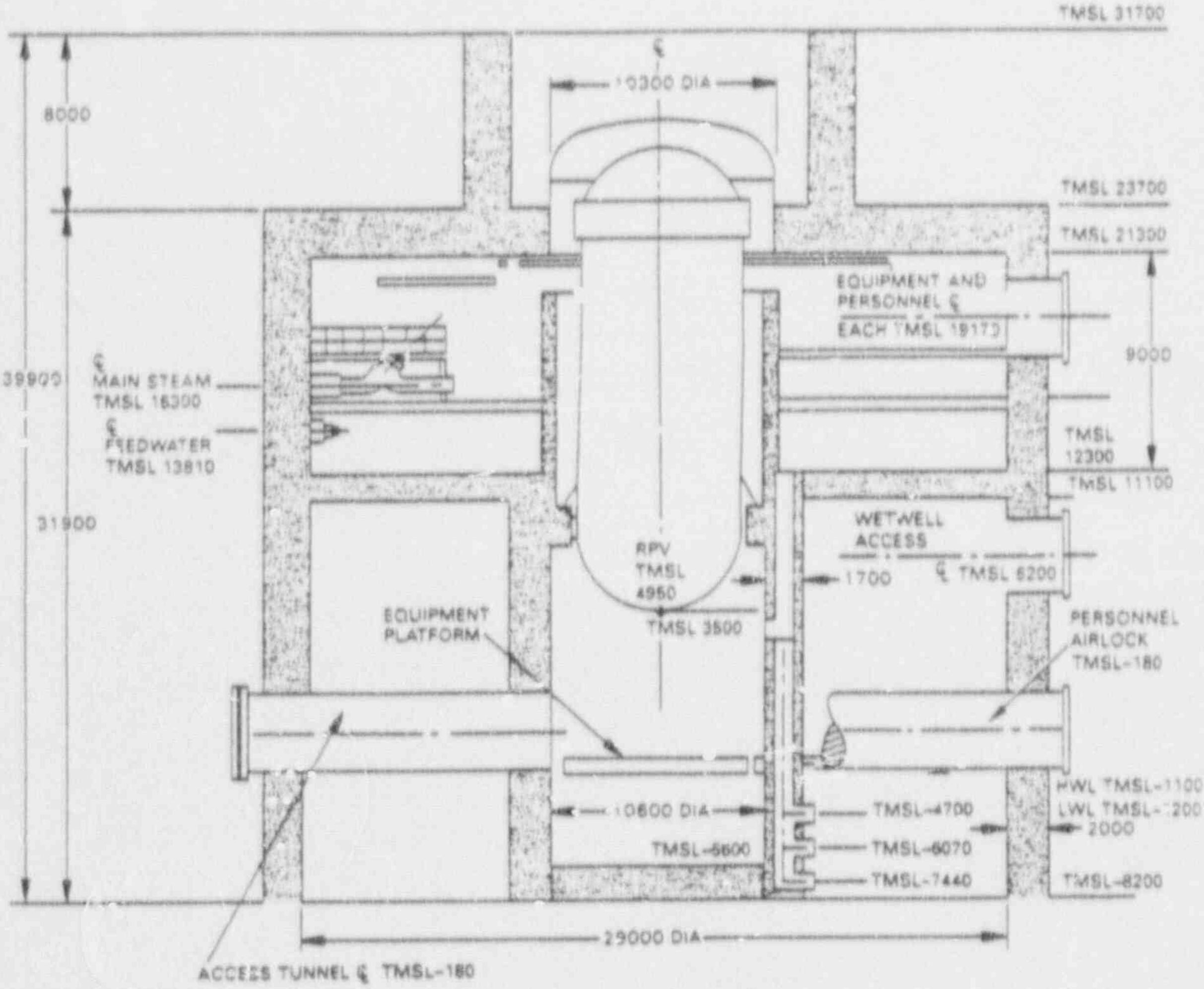


Figure 2.14.2a Reactor Building RCCV Internal Structures Nomenclature



NOTES:
1. DIMENSIONS ARE IN MILLIMETERS

Figure 2.14.2b Primary Containment Configuration

2.14.3 Reactor Pressure Vessel Pedestal

Design Description

The reactor pressure vessel pedestal located in the lower drywell consists of a composite steel and concrete filled structure rising from the base mat to the reactor vessel skirt support bracket and reactor shield wall base support element. Cast into the pedestal base mat are the drywell HCW (identified leakage) sump and drywell LCW (unidentified leakage) sump. Sections of the unfilled steel pedestal contain the upper and lower drywell to suppression pool submerged vents and the upper to lower drywell pipe and conduit spaces in the rectangular portions of the drywell to suppression pool vent openings. Welded to the pedestal wall are the personnel access and equipment transfer tunnels spanning the suppression chamber above the suppression pool. The pedestal carries the equipment platform perimeter support rails, undervessel control rod drive and fine motion control rod drive restraint beams, lower vessel and under vessel head insulation supports, reactor internal recirculation pump supports, and reactor internal recirculation pump cover lifting hoist stub beam.

Refer to Figure 2.14.3 Reactor Pressure Vessel Pedestal.

Main features include:

The lower drywell pedestal structure has the capability to maintain its functional integrity during and following the peak transient pressures and temperatures caused by the worst LOCA pipe break postulated to occur simultaneously with loss of offsite power and a safe shutdown earthquake. The pedestal structure is designed to accommodate the full range of loading conditions associated with normal and abnormal operations including the LOCA related design loads. Negative pressure differences between the drywell and wetwell are accommodated by eight vacuum breaker valves, piping and sleeves penetrating the pedestal wall. These 20-inch diameter vacuum breaker valves are designed to begin opening at a wetwell to drywell pressure differential of 0.1 psig and are fully open at 0.5 psig. They return the non-condensable gases to the drywell. These gases passed with the steam released from the pipe break in the drywell through the drywell to wetwell vents into the suppression pool where the gases were released into the wetwell air space and increased the wetwell airspace pressure.

The pedestal structure is designed to withstand coincident fluid jet forces associated with outflow from the postulated rupture of any pipe within the primary containment.

The pedestal structure is designed to accommodate flooding to a depth below the five return openings provided in the drywell wetwell vertical vents.

The pedestal structure is protected from and designed to withstand hypothetical missiles from sources within the primary containment and pipe whip due to the uncontrolled motion of broken pipes.

The pedestal structure is configured to channel flow from postulated pipe ruptures in the lower drywell to the pressure suppression pool designed with the required vent submergence and water volume to accommodated the energy of the fluid released.

The lower drywell floor shall have a low carbon dioxide forming type concrete to resist formation and release of carbon dioxide when in potential contact with the reactor corium during a severe accident.

The pedestal structure and eight vacuum breaker penetrations with concurrent operation of other accident mitigation systems, are designed to limit suppression pool bypass leakage during and following a postulated design basis accident to values well below leakage calculated for allowable wetwell pressures and temperatures. Leakage tests are described below.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.14.3 provides the definition of the inspections, tests and/or analyses together with the associated acceptance criteria which will be undertaken for the Reactor Pressure Vessel Pedestal.

Table 2.14.3: Reactor Pressure Vessel Pedestal

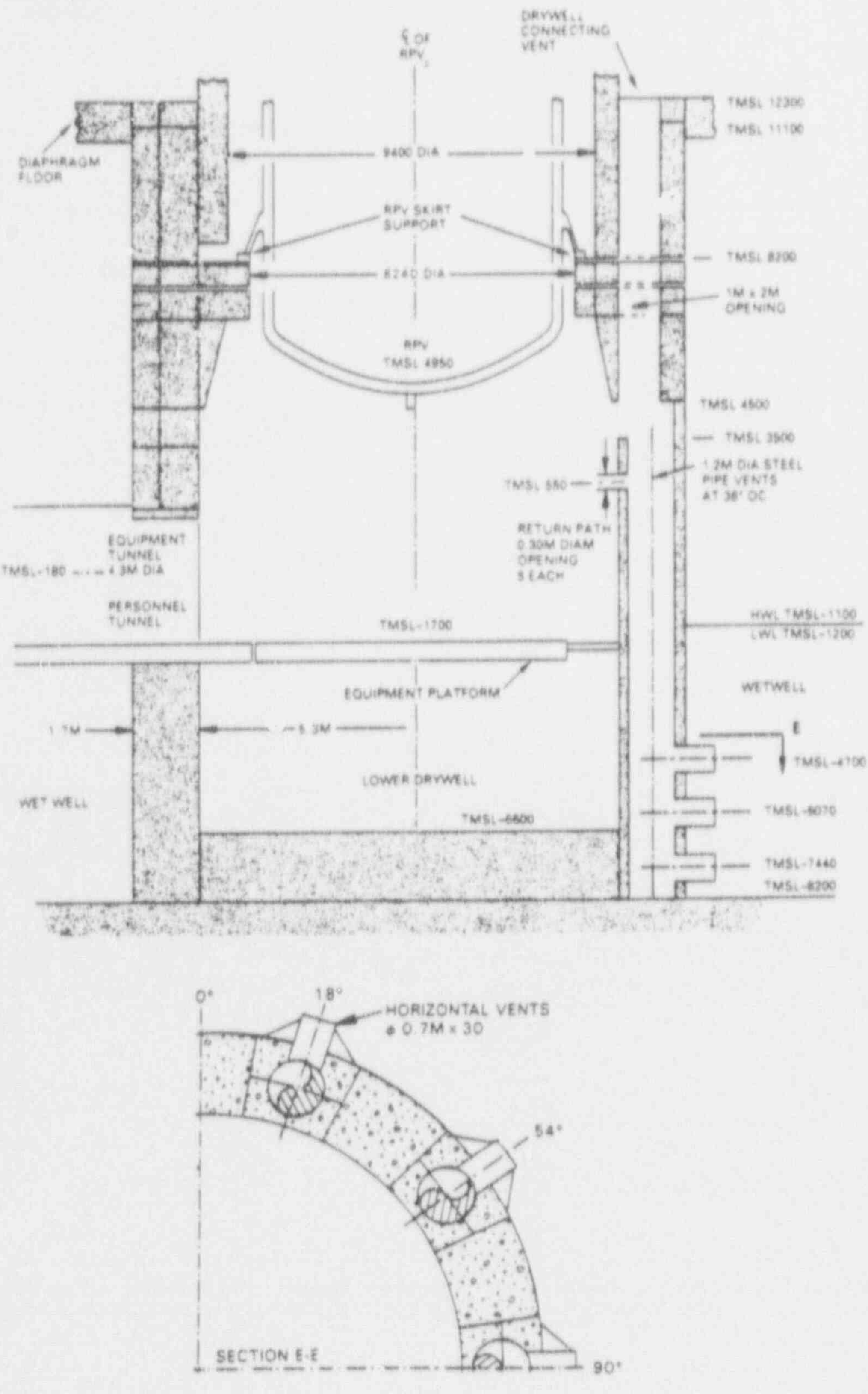
Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The Reactor Pressure Vessel (RPV) Pedestal is shown in Figure 2.14.3a.	1. Review the as-built RPV Pedestal construction records to verify it matches the design. Inspection of the configuration will verify the installation matches the design.	1. As-built RPV Pedestal construction conforms to the design configuration shown in Figure 2.14.3a.
2. The RPV Pedestal is designed to Safety Class 3, Quality Group C and Seismic Category I requirements.	2. Review the as-built construction records to verify the RPV Pedestal meets the design requirements	2. Confirm by visual inspection of as-built construction records the RPV Pedestal has been designed and built to comply with applicable codes and regulatory requirements.
3. The RPV Pedestal Drywell to Wetwell Vent System consists of ten vents sized 1 M by 2 M between the Drywell floor at elevation 7350 mm and the Lower Drywell at elevation (-)1450 mm. Below this elevation the ten vents are 1.2 M diameter down to elevation (-) 13150 mm. Three rows of ten 0.7 M diameter horizontal vents 1500 mm in length are placed at centerline elevations of (-)12,390 mm, (-)11,020 mm and (-) 9,650 mm as shown in Figure 2.14.3a.	3. Review the as-built construction records to verify the Drywell to Wetwell Vent System is configured as shown on Figure 2.14.3a. Inspect the construction installation of the Drywell to Wetwell Vent System to verify the installation matches the design documentation.	3. Confirm the RPV Pedestal Drywell to Wetwell Vent System has been designed, fabricated and installed in accordance with the design documentation.
4. The RPV Pedestal Drywell to Wetwell Vent System has been designed Safety Class 2, Quality Group B and Seismic Category I requirements.	4. Confirm the RPV Pedestal Drywell to Wetwell Vent System has been designed, fabricated and installed in accordance with the design documentation.	4. Confirm the RPV Pedestal Drywell to Wetwell Vent System has been designed, fabricated and installed to Safety Class 2, Quality Group B and Seismic Category I requirements.
5. Five of the Drywell to Wetwell Vertical Vents are provided with a 0.3 M diameter return paths at elevation (-) 1450 to insure the flood level in the lower drywell is controlled. These return path vents are designed to Safety Class 2, Quality Group B, Seismic Category I requirements.	5. Review the as-built construction documentation of the installed return path vents and verify by inspection that these vents have been installed in conformance with the design documentation.	5. Confirm the five 0.3 M diameter return path vents have been installed at elevation (-) 1450 mm and connect to the 1.2 M diameter vertical vents. Also confirm these return path vents have been designed, fabricated, and installed to Safety Class 2, Quality Group B and Seismic Category I requirements.

Table 2.14.3: Reactor Pressure Vessel Pedestal (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. The Lower Drywell floor is sealed with a steel liner which surrounds the outer leak detection tanks of both the Low Level Waste Sump and the High Level Waste Sump.	6. Review the as-built construction documentation of the Lower Drywell floor liner and the Low Level Waste Sump and the High Level Waste Sump.	6. Confirm the as-built configuration of the Lower Drywell floor contains the Low Level Waste Sump, the High Level Waste sump and the floor has a steel liner.
7. The RPV Pedestal wall contains ten equally spaced 100 mm Lower Drywell flooders mounted in ten vertical vents 1 M above the Lower Drywell floor. Each flooder is designed to release suppression pool water into the Lower Drywell when the Drywell temperature reaches 500 DEG. F.(260 DEG.C.). The Lower Drywell flooders are designed to Safety Class 2, Quality Group B and Seismic Category I requirements and meet the severe accident potential conditions.	7. Visually inspection the ten lower drywell flooders to verify they are 100 mm or larger equally spaced around the Lower Drywell and are 1 M above the lower Drywell floor. Verify each flooder is equipped with a thermal plug valve rated to open at a temperature of 500 DEG F. Also verify the flooders are designed, fabricated, tested and installed to Safety Class 2, Quality Group B and Seismic Category I requirements.	7. Confirm by inspection of the as-built documentation and by visual observation, there are ten 100 mm drywell flooders with 500 DEG. F. rated thermal plug valves mounted 1 M above the Lower Drywell floor and equally spaced around the pedestal wall at ten of the vertical drywell to wetwell vents. Also conform the thermal plug valves were designed, fabricated, installed and tested in accordance with the design documentation.
8. During abnormal and accident conditions the	8. Tests and visual inspection of each	8. As-built operational tests and visual inspections shall confirm that
9. Isolation dampers are designed to isolate	9. Demonstrate with a simulated.	9. Confirm the isolation



Note: Dimensions are in millimeters unless noted

Figure 2.14.3 RPV Pedestal

2.14.4 Standby Gas Treatment System

The Standby Gas Treatment System (SGTS) has the capability to filter the gaseous effluent from the primary containment or from secondary containment when required to limit the discharge of radioactivity to the environment.

The SGTS is designed to accomplish the following:

(1) Maintain a negative pressure in the secondary containment, relative to the outdoor atmosphere, to control the release of fission products to the environment.

(2) Filter airborne radioactivity (halogen and particulates) in the process stream to reduce off-site doses.

(3) Ensure that failure of any active component, assuming loss of off-site power, cannot impair the ability of the system to perform its safety function.

The SGTS consists of two parallel and redundant trains of active equipment which share a single filter train. Suction is taken from above the refueling flor or from the primary containment via the Atmospheric Control System. The discharge goes to the main plant stack.

The SGTS consists of the following principle components:

(1) Two independent dryer trains consisting of a moisture separator and an electric process heater.

(2) Two independent process fans located upstream of the filter train.

(3) A filter train consisting of a prefilter, a high efficiency particulate air (HEPA) filter, a charcoal adsorber, a second HEPA filter, and space heaters.

Instrumentation strictly required for monitoring the operation of the SGTS to mitigate off-site releases is provided in the main control room (MCR) on panel displays designed for that purpose. Instrumentation used for testing or maintenance is located at the local instrument rack.

There are two basic parameters that are important to assure SGTS function, secondary containment pressure and charcoal adsorber inlet relative humidity. If the secondary containment pressure is less than the ambient pressure, any release from the plant passes through and is treated and monitored by the SGTS. If the inlet relative humidity to the charcoal adsorber is less than or equal to 70%, then credit for a 99% efficiency may be taken. If the operator confirms the secondary containment pressure is negative with respect to ambient on all faces of the building and the relative humidity is less than 70% entering the adsorber, then the system is functioning as intended to mitigate calculated off-site doses.

The ABWR SGTS design provides four divisional differential pressure transmitters with high and low alarms monitoring secondary containment pressure with respect to ambient pressure outside each of the four walls of the Reactor Building. In addition, four divisions of moisture measurement with high alarms are provided in the filter housing upstream of the charcoal adsorber, providing a direct measurement of relative humidity. These basic parameters each have main control room indication and alarm.

Figure 2.14.4 shows the major system components. Key equipment performance requirements are:

(1)	Fan capacity (minimum)	4000 scfm
(2)	Dryer train outlet relative humidity	70%
(3)	Filter train charcoal weight (nominal)	1750 lb

A slight negative pressure is normally maintained in the secondary containment by the Reactor Building HVAC system. Upon the receipt of a high primary containment pressure signal or a low reactor water level signal, or when high radioactivity is detected in the secondary containment or refueling floor ventilation exhaust, the SGTS is automatically actuated. Upon SGTS initiation, the secondary containment is automatically isolated from the HVAC system. If SGTS operation is not confirmed, the redundant process fan and dryer train are automatically placed into service. In the event a malfunction disables an operating process fan or dryer train, the standby process fan and dryer train are manually initiated. The SGTS has independent, redundant active components. Should any active component fail, SGTS functions can be performed by the redundant component.

The SGTS is on standby during normal plant operation and may be manually initiated before or during primary containment purging (i.e., de-inerting) when required to limit the discharge of contaminants to the environment. If purging through the HVAC could or does result in a trip from the ventilation exhaust radiation monitors, then de-inerting can be [re-]initiated at a reduced rate through the SGTS. Use of SGTS during de-inerting is very infrequent. The SGTS may be manually initiated whenever its use may be needed to avoid exceeding radiation monitor set points.

Cooling of the SGTS filters may be required to prevent the gradual accumulation of decay heat in the charcoal. This heat is generated by the decay of radioactive iodine adsorbed on the SGTS charcoal. The charcoal is typically cooled by the air from the process fan. A water deluge capability is provided for fire protection. Water is supplied from the fire protection system and is connected to the filter train via a removable spool piece.

The SGTS, except for the deluge, is designed and built to meet the requirements for Safety Class 3 equipment. The electrical devices of independent components are powered from separate Class 1E electrical buses. The SGTS is designed to Seismic Category I requirements and is housed in a Category I structure. The construction materials used for the SGTS are compatible with normal and accident environments postulated for the area in which the equipment is located.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.14.4 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the SGTS.

Table 2.14.4: Standby Gas Treatment System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The SGTS shall be capable of maintaining a negative pressure of at least 0.25 inches w.g. and the relative humidity of the process stream entering the filter train below 70%. Each SGTS fan capacity shall be at least 4000 scfm measured with secondary containment not isolated.	1. System preoperation tests will be conducted to demonstrate acceptable fan and filter performance. These tests will be conducted at steady state conditions.	1. It must be shown either SGTS fan can maintain the secondary containment at a negative pressure of at least 0.25 inches w.g. with the associated dryer maintaining the outlet relative humidity below 70%. With secondary containment not isolated, fan capacity shall be at least 4000 scfm.
2. A simplified system configuration as shown in Figure 2.14.4.	2. Inspections of installation records together with plant walk-downs will be conducted to confirm that the installed equipment is in compliance with the design configuration defined in Figure 2.14.4.	2. The system configuration is in accordance with Figure 2.14.4.
3. The dryer, fan and associated valves can be powered from the standby AC power supply as described in Section 2.2.4.	3. System tests will be conducted after installation to confirm that the electrical power supply configurations are in compliance with design commitments.	3. The installed equipment can be powered from the standby AC power supply.
4. SGTS components which are required to maintain negative pressure in secondary containment are classified Seismic Category I.	4. Review associated documentation.	4. Components meet Seismic Category I requirements.

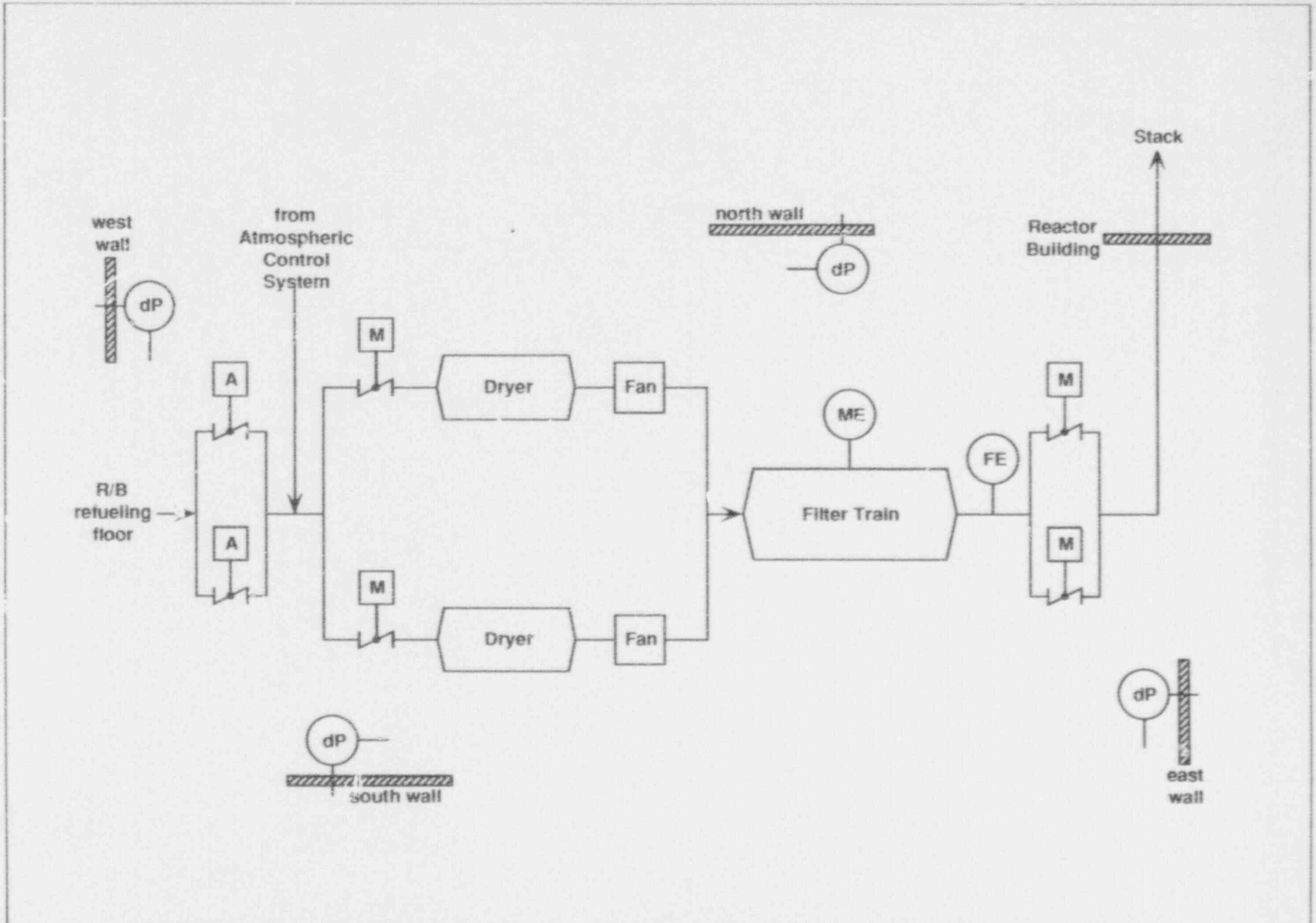


Figure 2.14.4 Standby Gas Treatment System

2.14.5 PCV Pressure and Leak Testing Facility

No Tier 1 ITAAC for this system.

2.14.6 Atmospheric Control System

Design Description

The Atmospheric Control (AC) System is designed to establish and maintain an inert atmosphere within the primary containment during all plant operating modes except during shutdown for refueling or equipment maintenance and during limited periods of time to permit access for inspection at low reactor power.

The AC System is not safety-related with the exception of the primary containment isolation portion which is required to maintain containment integrity.

The AC System consists of a pressurized liquid nitrogen storage tank, a steam-heated nitrogen vaporizer, injection lines, exhaust lines, bleed line, overpressure protection line, associated valves, controls and instrumentation. All AC System components are located inside the reactor building except the liquid nitrogen storage tank and the steam-heated nitrogen vaporizer which are located in the yard.

The AC System is designed to non-seismic class, Quality Group D requirements. The primary containment penetrations up to and including the outermost isolation valves are designed to Seismic Category I, Quality Group B.

The AC System has several modes of operation, namely: (a) Inerting, (b) Makeup, (c) De-inerting, and (d) Overpressure Protection.

The inerting process is performed during plant startup. This is accomplished by allowing large volume of liquid nitrogen to flow from the nitrogen storage tank, vaporized and heated up to appropriate temperature by the steam-heated vaporizer. The vaporized and heated nitrogen gas is then injected into the drywell and into the wetwell air space through penetration nozzles. The containment atmosphere should be inert to about 3.5% Oxygen by volume within 24 hours.

Following the inerting process, the makeup mode takes over to maintain the containment in inert state after manual realignment of system valves. Small volume of liquid nitrogen from the storage tank is heated up and gasified by an electric heater. The containment pressure is kept constant at slightly higher than the secondary containment. In response to changes in the containment pressure, the pressure control valve modulates (open/close) to provide nitrogen makeup thereby maintaining containment pressure. An increase in containment pressure over the normal operating range is controlled by venting through the bleed line. During this mode, nitrogen makeup to the HPIN System is also provided. Isolation signal override capability are provided to the makeup valves such that continued nitrogen makeup can be accomplished as required.

During plant shutdown, the containment is de-inerted with breatable air to allow personnel access inside the containment. Air is provided by the RBHVAC System utilizing fans to displace nitrogen. The oxygen volumetric concentration in the containment should be at least 18 % within 24 hours.

The AC System exhaust is directed to the RBHVAC exhaust line which undergo filtration and rad monitoring before being discharged to the plant stack. In the event high radioactivity is detected during venting or purging, the AC System exhaust to the RBHVAC exhaust is isolated and the flow is diverted to the Standby Gas Treatment System (SGTS) for treatment before discharging to the plant stack. The AC System exhaust flow from the containment is through the bleed valve and the SGTS vent valve which are both operable from the main control room with isolation signal override capability.

The AC System is designed to relieve the wetwell air space should an overpressure condition develop. A piping relief line with two normally open valves and two rupture disks is connectad to the AC System wetwell exhaust line. The relief line is designed to passively relieve the wetwell vapor space pressure of about 5.6 kg/cm^2g (80 psig). The normally open valves can be remote manually closed from the main control room to re-establish containment isolation following the opening of the rupture disks as required.

The AC System also includes instrumentation required for the operation of other safety-related systems. These instrumentation are as follows:

(1) Suppression pool water level instrumentation.

(2) Differential pressure instrument between drywell and wetwell.

(3) Containment water level instrument.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.14.6 provides a definition of the inspections, tests and/or analyses together with associated criteria which wil! be undertaken for the AC System.

Table 2.14.6: Atmospheric Control System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the AC System is shown in Figure 2.14.6.	1. Inspection of the as-built AC System configuration shall be performed.	1. Verification of the as-built conformance with the as-designed configuration (Figure 2.14.6).
2. The AC System PCV isolation valves isolate upon receipt of auto isolation signals from the Leak Detection System within 30 seconds.	2. Functional testing shall be performed on the system logic by simulating the auto isolation signal from the Leak Detection System within 30 seconds.	2. Valves isolate upon receipt of auto isolation signal within 30 seconds.
3. The AC System PCV isolation valves fail close on loss of power and/or air supply to the valve operators.	3. Field testing shall be performed to demonstrate that the AC System PCV isolation valve will fail in the safe direction (close) when power and/or air supply are removed.	3. Valves closure upon removal of power and/or air supply.
4. Override capability of the AC System makeup valves, bleed valve, and the SGTS vent valve following an isolation event.	4. Functional testing shall be performed on the system logic to demonstrate the override capability of the makeup valves, bleed valve and the SGTS vent valve following an isolation event utilizing a keylock switch from the main control room.	4. Opening of the makeup valves, bleed valve, and the SGTS vent valve in the presence of an isolation signal.
5. The containment overpressure protection rupture disk will open when containment pressure reaches to about 5.6 kg/cm^2g (80 psig).	5. Vendor testing shall be performed to verify actual disk rupture pressure against the required pressure setting of 5.6 kg/cm^2g (80 psig).	5. Verification of vendor documents certifying actual disk rupture pressure and that the supplied rupture disks are all identical (part of the same batch and are made from the same metallic sheet).
6. The containment overpressure protection line isolation valves can be remote manually closed to re-establish containment isolation.	6. Field testing shall be performed to demonstrate remote manual closure of the overpressure protection line isolation valves from the main control room.	6. Valves remote manual closure from the main control room.
7. Provision for instrumentation specified in Section 2.14.6.	7. Inspection shall be performed to verify presence of instrumentation specified in Section 2.14.6	7. Presence of instrumentation specified in Section 2.14.6.

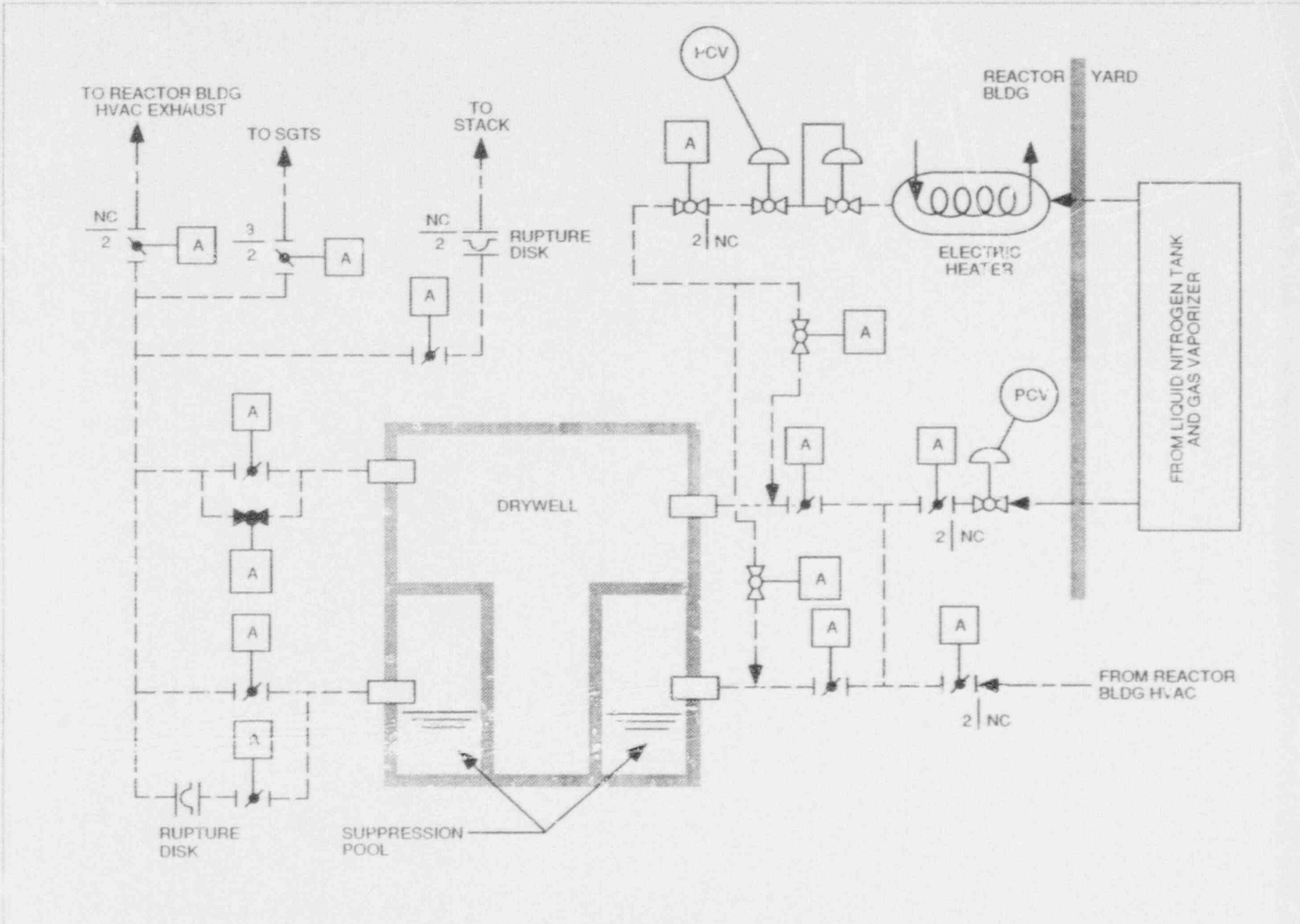


Figure 2.14.6 Atmospheric Control System

2.14.7 Drywell Cooling System

Design Description

The Drywell Cooling (DWC) System is designed to maintain the average drywell temperature at or below 57°C, and maximum local temperature at or below 65°C during normal plant operation. The system also maintains the average drywell temperature at or below 25°C during plant test or maintenance period.

The DWC System is an air/nitrogen recirculating system consisting of three fan coil units and two HVAC normal cooling water (HNCW) cooling units. A fan coil unit consists of a reactor building cooling water (RCW) cooling coil and a fan, and the HNCW cooling unit consists of a cooling coil only. Normally two of the three fan coil units, and both HNCW units are in operation. The third fan coil unit serves as a standby unit. The conditioned air/nitrogen is distributed to the various zones in the drywell. Each cooling unit is provided with a drain pan that collects water vapor condensed over the cooling coil. The condenstate from each drain pan in collected in a common header and is piped to a leak detection system (LDS) flowmeter. The system configuration is shown on in Figure 2.14.7

During loss of off-site power (in the absence of loss of coolant accident (LOCA) signal), the fans are automatically powered from the on-site source, and only RCW system water is available for cooling. The system is not operated in the presence of a LOCA signal.

The entire DWC system is classified as a nonsafety-related, non-seismic system.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.14.7 provides a definition of the inspection, tests and/or analyses together with associated acceptance criteria which will be undertaken for the DWC system.

Table 2.14.7: Drywell Cooling System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the DWC System is shown in Figure 2.14.7.	1. Inspection of the as-built DWC System configuration shall be performed.	1. As-built DWC System configuration for those components shown, conforms with Figure 2.14.7.
2. The DWC System fans operate when powered from both normal off-site and on-site sources.	2. DWC System functional test shall be performed to demonstrate fan operation when supplied by either normal off-site power or from the on-site power source.	2. DWC System fans operate when supplied by either power source.

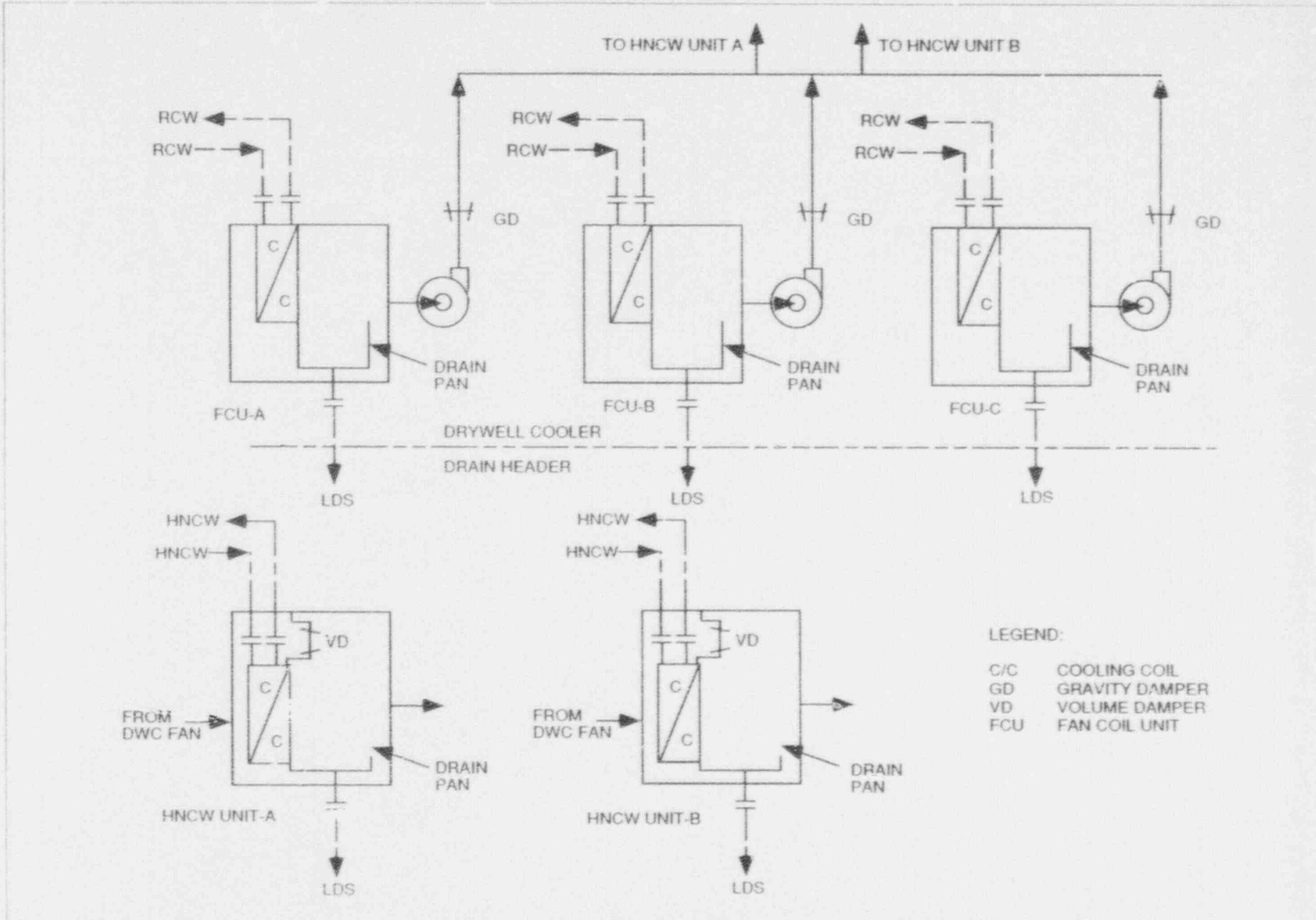


Figure 2.14.7 Drywell Cooling (DWC) System

2.14.8 Flammability Control System

Design Description

The Flammability Control System (FCS) is provided to control the potential buildup of oxygen in the containment from design basis radiolysis of water. The primary containment during normal operation is purged with nitrogen and maintained in an oxygen deficient condition (≤3.5 volume percent) by the Atmospheric Control System (ACS). The objective of these two systems together (ACS and FCS) is to preclude combustion of hydrogen and damage to essential equipment and structures.

The FCS consists of two identical thermal hydrogen recombiners, with associated piping, valves, controls and instrumentation. The recombiner units are located in the secondary containment and controlled from the main control room. Each recombiner removes gas from the drywell, recombines the oxygen with hydrogen, and returns the gas mixture, along with the condensate to the suppression chamber. After a LOCA, the system is manually actuated from the control room when high oxygen levels are indicated by the Containment Atmospheric Monitoring System (CAMS). Once placed in operation, the system continues to operate until it is manually shut down when an adequate margin below the oxygen concentration design limit is reached.

Operation of either recombiner will provide effective control over the buildup of oxygen generated by radiolysis after a design basis LOCA. Independent drywell and suppression chamber penetrations are provided for the two recombiners. Each penetration has two normally closed isolation valves; one air or nitrogen operated and one motor operated.

Each recombiner unit is an integral package. All pressure-containing equipment, including piping between components, is considered an extension of the containment and therefore is designed to ASME Section III, Safety Class 2 requirements. The entire package is designed to meet Seismic Category I requirements. The recombiners are in separate rooms in the secondary containment and are protected from damage by flood, fire, tornadoes and pipe whip.

The recombiner unit consists of a blower, electric heater, reaction chamber, water spray cooler, a water separator, piping, valves, controls and instrumentation. During operation of the system, gas is drawn from the drywell by the blower and heated. Hydrogen and oxygen in the gas will be recombined into steam in the reaction chamber and condensed in the spray cooler. The condensate and spray water, along with some of the gas, are returned to the wetwell. The rest of the gas is recycled through the blower.

The operation of the system can be tested from the control room. The test consists of energizing the blower and heaters and observing system operation to see if components are performing properly. Flow and pressure measurement devices are periodically calibrated.

Cooling water required for operation of the system after a LOCA is taken from the RHR System. Demineralized water is used for functional testing of the recombiner units. The cooling water is used to cool the water vapor and the residual gases leaving the recombiner prior to returning them to the containment.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.14.8 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the FCS.

2.14.9 Suppression Pool Temperature Monitoring System

Design Description

The Suppression Pool Temperature Monitoring System (SPTM) is a Safety-Related system designed to provide the operator with suppression pool temperature information. The SPTM system is a redundant system which is powered from two separate safety divisions. The SPTM system provides individual temperature indication from both divisions in the main control room and at the remote shutdown station and bulk average temperatures from both divisions for indication, trending, recording and alarm in the main control room. The temperature sensors are arranged in six circumferential locations around the pool such that they are out of the direct path of jet impingement from the horizontal vents or SRV quenchers and still be in direct sight of a SRV discharge. Each sensor location contains four vertical sensors from each division so as to reliably measure the bulk average pool temperature. All temperature sensors are located below normal pool water level and at a sufficient distance from pool walls to provide accurate local temperature measurement. Sensors are physically separated between redundant divisions and terminated in moisture protected junction boxes in the wetwell for sensor replacement. Temperature signal processing is designed such that a sensor division can be bypassed for maintenance or calibration and any failed or uncovered sensor (e.g. pool water level below sensor) will be excluded from the bulk averaging process, identified and annunciated. Divisional SPTM system outputs are electrically isolated when provided for use other than within its respective division (e.g. process computer).

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.14.9 provides a definition of the Inspections, Tests, and/or Analysis, together with the associated Acceptance Criteria which will be undertaken for the Suppression Pool Temperature Monitoring System.

Table 2.14.9: Suppression Pool Temperature Monitoring System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The Suppression Pool Temperature Monitoring System (SPTM) is a safety-related system designed to provide the operator with two divisions of suppression pool temperature indication. Individual temperature indication from both divisions is provided in the main control room and at the remote shutdown system. Bulk average temperature indication, trending, and sensor failure or sensor uncovered annunciation is provided in the main control room.	1. Inspection will be performed to confirm that two divisions of individual temperature sensor indications are provided in the main control room and at the remote shutdown system and that bulk average temperatures are indicated, trended, and recorded, and system failures are annunciated in the main control room.	1. Inspection confirms that two divisions of individual temperature indication is provided to the main control room and remote shutdown system and that bulk average temperatures are indicated, trended, and recorded and that system failures are annunciated in the main control room.
2. The SPTM system temperature sensors are arranged in circumferential locations around the pool in locations such that they are out of the direct path of jet impingement from horizontal vents and SRV quenchers and are still in direct sight of a SRV discharge.	2. Inspection will be performed to confirm that SPTM temperature sensors are provided in six locations around the pool out of the direct path of jet impingement from horizontal vents and SRV quenchers and are in direct sight of an SRV discharge.	2. Inspection confirms that SPTM temperature sensors are provided in six locations around the pool out of the direct path of jet impingement from horizontal vents and SRV quenchers and are in direct sight of an SRV discharge.
3. Each location of SPTM temperature sensors contains four vertical sensors from each division, installed below normal pool low water level. Sensors are separated between divisions and terminated in moisture protected junction boxes in the wetwell for sensor replacement.	3. Inspection will be performed to confirm that each SPTM temperature sensor location contains four vertical sensors from each division, installed below normal pool low water level, and are separated between divisions and terminated in moisture protected junction boxes in the wetwell.	3. Inspection confirms that each SPTM temperature sensor location contains four vertical sensors from each division, installed below normal pool low water level, and are separated between divisions and terminated in moisture protected junction boxes in the wetwell.
4. Electrical independence and physical separation is maintained between divisions of SPTM system components and wiring and any output provided for use other than within its respective division is electrically isolated.	4. Inspection will be performed to confirm that electrical independence and physical separation is maintained between divisions of SPTM system components and wiring and any output provided for use other than within its respective division is electrically isolated.	4. Inspection confirms that electrical independence and physical separation is maintained between divisions of SPTM system components and wiring and any output provided for use other than within its respective division is electrically isolated.

Table 2.14.9: Suppression Pool Temperature Monitoring System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. Each division of the SPTM system can be bypassed for maintenance, calibration, and testing	5. Testing will be performed to confirm that each division of the SPTM system can be bypassed for maintenance, calibration, and testing	5. Testing confirms that each division of the SPTM system can be bypassed for maintenance, calibration, and testing

2.15 Structures and Servicing

2.15.1 Foundation Work

No entry. Covered by item 2.15.10.

2.15.2 Turbine Pedestal

No Tier 1 entry for this system.

2.15.3 Cranes and Hoists

Design Description

The ABWR Certified Design makes use of many Cranes and Hoists for maintenance and refueling tasks. These cranes and hoists ' ave load ratings greater than the heaviest expected loads to be applied as identified by site specific equipment lists for each item to be serviced.

The RB Crane used during refueling/servicing as well as when the plant is online. During refueling/servicing, the crane handles the shield plugs, drywell and reactor vessel heads, steam dryer/separators, etc. Minimum crane coverage includes RB refueling floor laydown areas, and RB equipment storage pit. During normal plant operation the crane used to handle new fuel shipping containers and the spent fuel shipping casks. Coverage include the new fuel vault, the RB equipment hatches, and the spent fuel cask loading and washdown pits.

The RB crane interlocked to prevent movement of heavy loads over the spent fuel storage portion of the spent fuel storage pool. These cranes are single failure proof, and can hold their load in an SSE.

The Upper Drywell Hoists are used during outages to service valves and equipment inside the Upper Drywell. These hoists are Seismic Category I.

The Lower Drywell Hoists are used during outages to service valves and equipment inside the Upper Drywell. These hoists are Seismic Category I.

The Mainsteam Tunnel Hoists are used during outages to service MSIV's and FWIV's inside the mainsteam tunnel.

Other Hoists and Cranes in the ABWR certified design are used to service and remove plant equipment.

Inspections, Tests, Analyses and Acceptance Criteria

This section provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the Cranes and Hoists.

Table 2.15.3 Cranes and Hoists Inspection, Tests, Analyses and Acceptance Criteria

Table 2.15.3: Cranes and Hoists

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. All cranes and hoists have a load rating in excess of the heaviest expected load per the site specific equipment lists for each item to be serviced.	1. Compare Crane and Hoist load ratings in purchase documents to verify that load ratings are in excess of expected lift.	1. Load Rating greater than the Heaviest Equipment To be Lifted
2. The RB Crane interlocked to prevent carrying heavy loads over the spent fuel portion of the spent fuel pool.	2. Review Purchase Documents for compliance with interlock.	2. The RB Crane is interlocked to prevent the carrying of heavy loads over the spent fuel portion of the spent fuel pool.
3. The RB Crane is single failure proof and can hold its load under an SSE.	3. Review Purchase Documents for compliance with redundancy and seismic capability requirements	3. RB Crane meets single failure proof criteria and will not drop its load under an SSE.
4. Upper and Lower Drywell Hoists are Seismic Category I.	4. Review design/purchase documents.	4. Upper and Lower Drywell Hoists are Seismic Category I.

2.15.4 Elevators

Design Description

The ABWR Certified design makes use of elevators to move operational personnel and light loads vertically within the plant.

Four elevators are located in the Reactor Building. Two in the corners of the secondary containment at 45 degrees and 225 degrees from plant north. Another two are located in the clean zone outside secondary containment at [illegible]0 degrees and 270 degrees.

One elevator is located inside the control building of the ABWR Standard Plant. It is located at 90 degrees near the entrance to control building from the service building.

One elevator is located inside the service building of the ABWR Standard Plant. It is located outside the door of the control building.

An elevator is located inside each of the Turbine Building and the Radwaste Building.

Inspections, Tests, Analyses and Acceptance Criteria

No entries for this system.

2.15.5 Heating, Ventilating and Air Conditioning

Design Description

Design Descriptions are provided for each of the following HVAC Systems: Control Building, Control Room Habitability Area, Reactor Building, Turbine Building, Electrical Building, Service Building and Radwaste Building. Tables for the Inspections, Tests, Analyses and Acceptance Criteria are included with ten HVAC System Figures.

Control Building HVAC Systems

Control Building safety-related air conditioning systems other than the Control Room Habitability Area, are designed to maintain 85°F, 50% RH at a slight positive pressure to provide efficient work environments for the operators and proper environments for structures and equipment to insure it has the capability to perform every safety function considering the worst case single failure for all normal and abnormal reactor operating conditions and accident conditions.

Air conditioning equipment to accomplish the above is designed to maintain efficient work environments for the operators and proper environments for equipment and structures.

Major equipment consists of redundant supply fans, prefilters, 80% efficiency filters, hot water heating coils, chilled water cooling coils, and recirculation/exhaust fans, backdraft dampers, fire dampers, and air distribution ducts and accessories. Bird screens, dust and insect filters are provided to protect heating and cooling coil efficiency. Corrosion resistant materials are used in the fabrication of fans, coils, cabinets, plenums, air ducts and accessories (see Figure 2.15.5a for a simplified design configuration).

All safety-related HVAC systems are served from Class 1E power from either normal off-site sources or on-site emergency diesel generators.

Electrical equipment rooms are maintained at a positive pressure, and air movement is designed to flow to the battery rooms maintained at a negative pressure by the exhaust fans.

Rooms housing the motor-generator (MG) sets, which provide power to the reactor internal pumps, are cooled by individual fan coil cooling units. These non-safety related cooling units are powered from the same electrical source as the MG set served. The HVAC Normal Cooling Water System connects to each fan coil unit cooling coil.

Smoke detectors are provided to initiate an alarm to close the return air dampers, open the fire zone damper bypassing th exhaust fans and start the supply fans to pressurize the Control Building compartments and discharge smoke through the exhaust louvers. The supply fans are located in mechanical rooms separate from the remainder of the Control Building compartments. The supply and exhaust fans can be started from the Control Room or the hand-off-automatic switches on the motor control center. These fans are powered from Class 1E Electrical Divisions 1,2 or 3.

Control Room Habitability Area HVAC System

The Control Room is maintained at a positive pressure for most events, 76°F, 42% relative humidity (RH) and is continuously habitable during LOCA, chemical release, fire, safe shutdown earthquake, tornado, flood, and other natural phenomena to insure that the operators can safely shut down the reactor and keep it in a safe shutdown condition.

Major equipment consists of redundant supply fans, prefilters, 80% efficiency filters, hot water heating coils, chilled water cooling coils, and recirculation/exhaust fans, backdraft dampers, fire dampers, and air distribution ducts and accessories. Bird screens, dust and insect filters are provided to protect heating and cooling coil efficiency. Corrosion resistant materials are used in the fabrication of fans, coils, cabinets, plenums, air ducts and accessories. The Control Room habitability equipment consists of redundant HEPA and charcoal filtration units designed to meet regulations addressing Control Room habitability during LOCA and other abnormal events. These units treat air from one of two widely separated air intakes with radiation monitors controlled to select the air intake with the non-contaminated air or isolate both in the event contaminants are present at both locations. Provisions are included for the future installation of site dependent toxic chemical monitors with controls capable of actuating the Control Room isolation dampers. The Control Room Habitability HVAC System is Seismic Category I, located in a Seismic Category I structure with air intakes and exhausts designed for protection from the effects of wind, rain, snow, tornados and tornado missiles (see Figure 2.15.5b for a simplified design configuration.

All safety-related HVAC components are served from Class 1E power from either normal off-site sources or on-site emergency diesel generators

Smoke detectors are provided to initiate an alarm to close the return air dampers, open the fire zone damper bypassing the exhaust fans and start the supply fans to pressurize the Control Room Habitability areas and discharge smoke through the exhaust louvers. The supply and exhaust fans are located in mechanical rooms separate from the remainder of the Control Room Habitability Area and can be started from the Control Room or the hand-off-automatic switches on the motor control center. These fans are powered from Class 1E Electrical Divisions II or III.

Reactor Building HVAC Systems

Reactor Building Secondary Containment is served from non-safety related HVAC equipment located in the Turbine Building and is designed to maintain temperatures between 65 to 104°F, 50% RH and hold a negative 0.25-inch water gauge pressure. Air supply and exhaust duct systems are balanced to cause air movement from clean areas to areas with potential airborne radioactive contamination. Redundant Secondary Containment isolation dampers in series are provided in the main air supply and exhaust ducts where they enter the Reactor Building. These isolation dampers close whenever high airborne radiation is detected in the exhaust duct or in the Refueling Floor exhaust air intake, or when the fans fail or are not operating. These isolation dampers are safety related, Seismic Category I with Seismic Category I supports and have normally open, fail closed air operators powered from Class 1E Electrical Divisions I or II.

Secondary Containment air conditioning and heating equipment consists of three 50% air supply fans moving 100% outdoor air which is filtered with bag-type filters, heated with hot water coils or cooled with chilled water coils before the air is distributed through air ducts to and within the Secondary Containment. Exhaust air from the Reactor Building Secondary Containment compartments is collected in ducts, monitored for radiation and drawn to three 50% exhaust fans discharging into the plant stack. Seismic Category I duct supports are provided where air ducts could fall on safety-related equipment. The Primary Containment supply fan, filter and purge exhaust fan are not safety-related and serve the Primary Containment Atmospheric Control System (see Figure 2.15.5c for a simplified design configuration).

Essential Equipment HVAC System is safety related and consists of cabinet cooling (HVH), units containing fans and cooling coils connected to the Reactor Cooling Water System. Individual HVH coolers are provided for each compartment housing the following safety-related equipment: (1) Emergency Core Cooling System (ECCS) consisting of three Residual Heat Removal (RHR) pumps and heat exchangers, (2) two High Pressure Core Flooding (HPCF) pumps; (3) one Reactor Core Injection Cooling (RCIC) steam turbine pump; (4) two Flammability Control System (FCS) recombiners; (5) two Standby Gas Treatment System (SGTS) filter/dryer units and the two Containment Atmospheric Monitoring System (CAMS) equipment rooms. Each room cooler is controlled to start when the equipment served starts or when the respective space thermostat calls for cooling.

The main steam tunnel has a non-safety-related cabinet cooler (HVH) containing cooling coils served from the HVAC Normal Cooling Water System. Two fans distribute air to the main steam (MS) and feedwater (FW) isolation valve areas. These units are manually started from the main Control Room and are designed to keep the temperature below 140°F. Other non-safety-related cabinet coolers (HVH) containing fans and cooling coils connected to the HVAC Normal Cooling Water System are provided for the Refueling Machine Control Room, the Inservice Inspection (ISI) Rooms and the Suppression Pool Cleanup System (SPCU) Equipment Room. These cabinet cooling units are controlled to start when the space thermostat calls for cooling.

Radiation monitors are provided in the air environment of the refueling floor and in the main air exhaust duct in the Reactor Building to cause closure of the main air supply and exhaust duct automatic isolation dampers whenever high airborne radiation occurs. This high radiation signal will also activate the Standby Gas Treatment System to maintain the negative 0.25-inch water gauge pressure within the Secondary Containment.

Smoke removal from any compartment of the Secondary Containment is accomplished by operating all three air supply fans and all three air exhaust fans with their filter bypass dampers opened. Air exhaust flow limiting dampers are actuated within the fire zones not experiencing the fire to pressurize these fire zones to limit smoke intrusion.

The remaining areas of the Reactor Building outside of Secondary Containment are served by individual HVAC supply and exhaust systems designed to keep the temperatures below 104°F.

Electrical Equipment HVAC consists of three safety-related systems, Seismic Category I, Safety Class 3, Quality Group C and are powered from their respective Class 1E Electrical Divisions 1, 2 or 3. Outdoor air and return air is mixed, filtered, cooled, and distributed to maintain a slightly positive pressure in the electrical equipment rooms and a slightly negative pressure in the Diesel Generator and Day Tank Rooms except when the diesel generators are running and their two emergency cooling fans operate to keep the temperature below 110°F. Smoke removal is accomplished by stopping the exhaust fans, closing the return air damper and opening the exhaust fan by-pass damper. Continuing to operate the supply fans pressurizes the areas served and releases the smoke through the exhaust bypass duct to the outdoors (see Figure 2.15.5d for a simplified design configuration).

Reactor Internal Pump (RIP) Rooms are supplied recirculated air cooled by HVAC normal cooling water coils and distributed by fans and air ducts. The return air is drawn into the RIP power supplies and control panels before being recooled. This RIP HVAC System is non-safety related and non-seismic except the air duct supports where safety related equipment is located (see Figure 2.15.5e for a simplified design configuration).

Fine Motion Control Rod Drive (FMCRD) Auto Exchanger Control Panel Rooms are served by three fan coil units (FCU) with cooling water supplied by the HVAC Normal Cooling Water System. These FCU's are not safety related.

Turbine Building HVAC Systems

Turbine Building is served from non-safety-related HVAC equipment located within the building to maintain less than 104°F, 50% RH and a slightly negative pressure except in electric switchgear rooms. Air supply and exhaust duct systems shall be balanced to cause air movement from clean areas to areas with potential airborne radioactive contamination.

Turbine Building air conditioning and heating equipment consists of three 50% ventilation system air supply fans moving 100% outdoor air which is filtered with bag type filters, cooled with chilled water coils or heated with hot water coils before the air is distributed through air ducts to and within the Turbine Building. General exhaust air from the Turbine Building is collected in ducts connected to three 50% ventilation system exhaust fans with bag filters discharging into the plant vent stack. Heat from the Turbine Operating Floor is removed by roof exhaust ventilating fans (see Figures 2.15.5f and 2.15.5g for the simplified design configurations).

Separate Lube Oil Area exhaust fans and ducts are provided to serve the LO storage and pump rooms to remove lubricating oil (LO) fumes and discharge them from the plant vent stack.

Compartments with potential radioactive contamination are collected in separate exhaust ducts and moved by the compartment exhaust fans with bag filters and radiation monitors to the plant vent stack.

Compartments housing heat releasing equipment are provided with multiple fan recirculation fan coil unit coolers with cooling coils and filters to keep temperatures below 104°F.

Smoke removal is accomplished with operation of the Turbine Building roof power exhaust ventilators, supply fans with the return air damper closed, exhaust fans with their exhaust filter bypass dampers opened and fire zone smoke dampers positioned to create a positive pressure in the areas adjacent to the zone experiencing the fire. The Turbine Building supply and exhaust fans can be started from the Control Room or the on-off-automatic switches on the motor control center in the Electrical Building.

Electrical Building HVAC Systems

Redundant air supply units with filters, cooling coils and fans are provided to maintain a positive pressure in the non-safety related Electrical Switchgear

Rooms. Return/exhaust fans and air ducts provide the ventilation. Recirculating fan coil unit coolers help maintain the temperature below 104°F in the Electrical Switchgear Rooms and the Air Compressor Room. A negative pressure in the Auxiliary Boiler Rooms and Combustion Gas Turbine Generator Room is accomplished with roof exhausters (see Figure 2.15.5h for a simplified design configuration).

Smoke removal is accomplished by closing the return air dampers and circulating all outdoor air within the Electrical Building. The Heating Boiler Room and Combustion Turbine Generator Room are maintained at a negative pressure relative to the Electrical Switchgear Rooms, Chiller Room, Air Compressor Room and the stair towers which are maintained at a positive pressure. Equipment rooms position their fire zone smoke dampers to increase pressurization when the fire is in an adjacent area. Supply and exhaust fans can be started and dampers aligned from the Control Room or the hand-off-automatic switches on the motor control center.

Service Building HVAC Systems

The Service Building is served from non-safety-related HVAC equipment located within the building to maintain 72°F, 50% RH and a slightly negative pressure except in corridors and electrical equipment rooms (see Figure 2.15.5i Service Building HVAC Systems for a simplified design configuration).

Service Building air supply to the nonradioactive area is provided with a mixture of outdoor and return air which is filtered, cooled, dehumidified or humidified and distributed by redundant fans through air ducts and diffusers to three reheat zones controlled by zone thermostats. Cooling is provided by the HVAC Normal Cooling Water System and reheat by the Hot Water Heating System. Air supply and exhaust duct systems are balanced to cause air movement from clean areas to areas with potential airborne radioactive contamination.

Service Building air supply to the potentially radioactive area is provided with 100% outdoor air which is filtered, cooled and distributed by redundant fans and air ducts to a single reheat zone controlled by a thermostat. The potentially radioactive area is maintained at a negative pressure by redundant exhaust fans which draw the exhaust air through filters before discharge to the vent stack. The exhaust air flow is controlled by a variable air operated damper with signals from a flow meter and radiation monitor.

Room cooling is supplemented by fan coil units with filters and cooling coils provided with HVAC normal cooling water. The Chemical Counting Room, Computer Room and Technical Support Center are provided with cooling units having redundant fans. The space temperature is controlled by thermostats modulating the HVAC normal cooling water valves.

Smoke removal can be accomplished by closing the non-radioactive controlled area return air damper to pressurize this area and positioning the fire zone smoke damper in the exhaust duct to by-pass the exhaust fans and remove the smoke through the exhaust louvers. The radioactive controlled area supply and exhaust fans circulate all outdoor air and normally maintain this area at a negative pressure compared to the non-radioactive controlled area. The radioactive controlled area exhaust fans can remove smoke from both the non-radioactive controlled area and the radioactive controlled area. Supply and exhaust fans and return air and fire zone dampers can be controlled from the Control Room or from the hand-off-automatic switches on the motor control center.

Radwaste Building HVAC Systems

The Radwaste Building is served from non-safety-related HVAC equipment located within the building to maintain 65 to 104°F, 50% RH and a slightly negative pressure except in the Radwaste Control Room. Air supply and exhaust duct systems are balanced to cause air movement from clean areas to areas with potential airborne radioactive contamination (see Figure 2.15.5j for a simplified design configuration).

Radwaste Building air supply to potentially radioactive areas is provided with 100% outdoor air which is filtered, cooled, and distributed by redundant fans and air ducts to several reheat zones each controlled by a thermostat. The potentially radioactive area is maintained at a negative pressure by redundant exhaust fans which draw the exhaust air through filters before discharge to the vent stack. The exhaust air flow is controlled by a variable air operated damper with signals from a flow meter and radiation monitor.

Radwaste Building process tanks are connected to a tank vent transfer system that equalizes air outflow from tanks being filled with air inflow needed for tanks being emptied. Any excess air is exhausted through a filter, radiation monitor and redundant exhaust fans to the plant vent stack.

The Radwaste Control Room is maintained at a positive pressure by varying the air flow to the redundant exhaust fans by a variable position damper.

Smoke removal is accomplished by opening the exhaust fan by-pass damper to enable the dual Radwaste Building air supply fans to be started to pressurize all areas. Smoke is discharged to the stack. The supply and exhaust fans can be controlled from the Radwaste Building Control Room or the hand-off-automatic switches on the motor control center.

Inspections, Tests, Analyses and Acceptance Criteria

The following tables provide the Inspections, Tests, Analyses and associated Acceptance Criteria which are to be accomplished for the plant HVAC systems.

Table	System
2.15.5a	Control Building HVAC Systems
2.15.5b	Control Room Habitability Area HVAC System
2.15.5c	Reactor Building HVAC Systems
2.15.5d	Turbine Building HVAC Systems
2.15.5e	Electrical Building HVAC Systems
2.15.5f	Service Building HVAC Systems
2.15.5g	Radwaste Building HVAC Systems

Table 2.15.5a: Control Building HVAC System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Control Building HVAC Systems are shown in Figure 2.15.5a.	1. Inspections of the as-built HVAC System construction records shall be performed. Visual inspection of the configuration shall be accomplished.	1. As-built Control Building HVAC System installations conform to the configuration for all components shown in Figure 2.15.5a.
2. Three Control Building HVAC trains are mechanically and electrically independent.	2. Tests and visual inspection of the three independent trains will be conducted which will include independent and coincident operation of the three trains to demonstrate complete divisional separation.	2. As-built operational tests and visual inspection shall confirm independence of the three electrical divisions.
3. Exhaust fan bypass dampers are designed to enhance smoke removal from the Control Building in the event of a fire inside or outside the Control Building. Refer to Table 3.2b, Ventilation and Airborne Monitoring.	3. Demonstrate and visually inspect the capability of each exhaust fan bypass damper to open, return air damper to close and the exhaust fans to be stopped from the Control Room or aligned and positioned from outside the Control Room with their hand-off-automatic (H-O-A) switches in the motor control center (MCC) to remove smoke from the Control Building.	3. Confirm that the Control Building exhaust fan bypass dampers are capable of being aligned and operated from inside or outside the Control Room and able to remove smoke from the Control Building.
4. Control Building HVAC equipment is designed to Safety Class 3, Quality Group C, Seismic Category I requirements and is powered from Class 1E Electrical Divisions 1, 2 or 3.	4. Review documentation of the installed equipment, instruments, ducts, piping and supports for compliance, and (if applicable) the Code Stamp on the hardware.	4. Confirm the system equipment is designed, fabricated, installed and tested in compliance with applicable codes and regulatory requirements. Visually inspect the electrical installation to confirm Class 1E Electrical Divisions 1, 2 and 3.

Table 2.15.5b: Control Room Habitability Area HVAC System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Control Room HVAC and Habitability System is shown in Figure 2.15.5b.	1. Inspections of the as-built HVAC and Habitability System construction records shall be performed. Visual inspection of the configuration shall be accomplished.	1. As-built configuration of the HVAC and Habitability System installation conforms with those components shown in Figure 2.15.5b.
2. Two Control Room HVAC and Habitability trains are both mechanically and electrically independent	2. Tests and visual inspection of the two independent trains will be conducted which will include independent and coincident operation of the two trains to demonstrate complete divisional separation.	2. As-built operational tests and visual inspection shall confirm independence of the two electrical divisions.
3. During abnormal and accident conditions the Control Room HVAC and Habitability trains are capable of responding to high radiation levels at one or both of the two air intakes.	3. Tests and visual inspection of each train operating in the abnormal or accident mode and using a simulated high radiation signal at one of the outdoor air intakes, confirm the logic will open the alternate air intake dampers and close the dampers at any intake detecting high airborne radiation.	3. As-built operational tests and visual inspections shall confirm that a simulated high radiation signal at one of the two outdoor air intakes will open the outdoor air damper at the alternate air intake. Also confirm that dampers at both air intakes close with simulated high airborne radiation signals at both outdoor air intakes.
4. Isolation valves are designed to isolate the Control Room during onsite or offsite chemical releases.	4. Demonstrate with a simulated signal from the chemical release sensor that the Control Room HVAC and Habitability isolation valves close to isolate the Control Room.	4. Confirm the isolation valves are in their design locations and are capable of completely isolating the Control Room and Habitability Areas from the outside environment upon receipt of an isolation signal.

Table 2.15.5b: Control Room Habitability Area HVAC System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. Exhaust fan bypass dampers are designed to enhance smoke removal from the Control Room in the event of a fire inside or outside the Control Building.	5. Demonstrate and visually inspect the capability of each exhaust fan bypass damper to be opened, each return air damper to be closed and the exhaust fans to be stopped by their remote manual switches (RMS) in the Control Room or the hand- off-automatic switches in the motor control center (MCC) outside the Control Room. All outdoor air pressurization of the Control Room removes the smoke through the exhaust louvers.	5. Confirm the Control Room smoke removal equipment is capable of being aligned and operated outside the Control Room and able to remove smoke from the Control Room.
6. Habitability air treatment equipment is designed to meet the requirements of applicable regulations and standards. Refer to Table 3.2b Ventilation and Airborne Monitoring.	6. Test and visually inspect the air treatment equipment to demonstrate that all of the components are ready to perform their function in accordance with applicable standards.	6. Confirm treatment equipment is in compliance with acceptance criteria of applicable standards relating its functional performance.
7. Control Room Habitability Area HVAC equipment is designed to Safety Class 3, Quality Group C, Seismic Category I requirements and are powered from Class 1E Electrical Divisions 2 or 3.	7. Review documentation of the installed equipment, instruments, ducts, piping and supports for compliance, and (if applicable) the Code Stamp on the hardware.	7. Confirm the system equipment is designed, fabricated, installed and tested in compliance with applicable codes and regulatory requirements. Visually inspect the electrical installation to confirm the Class 1E Electrical Divisions 2 and 3.

Table 2.15.5c: Reactor Building Heating, Ventilating And Air Conditioning (HVAC) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Reactor Building Secondary Containment HVAC System is shown in Figure 2.15.5c.	1. Inspections of the as-built HVAC System construction records shall be performed. Visual inspection of the configuration components shall be accomplished.	1. As-built Reactor Building Secondary Containment HVAC installation conforms to the configuration shown in Figure 2.15.5c.
2. Secondary Containment dual isolation dampers of the main air supply and exhaust ducts are designed to Safety Class 2, Quality Group B, Seismic Category I and are powered from Class 1E Electrical Divisions 1 or 2.	2. Review the documentation of the as-installed isolation dampers to verify compliance with the required standards and (if applicable) visually inspect the Code Stamp on the hardware.	2. Confirm by visual inspection the isolation dampers are designed, fabricated, installed and tested in compliance with codes and regulatory requirements.
3. Secondary Containment dual isolation dampers close in less than 30 seconds due to a LOCA signal or detection of high airborne radioactivity upstream of these isolation dampers or at the exhaust air intake duct in the Refueling Area or failure of system fans. Refer to Table 3.2b Ventilation and Airborne Monitoring.	3. Test the closure of the Secondary Containment HVAC main dual supply and exhaust isolation dampers with simulated isolation signals. Verify that closure of each isolation valves occurs in less than 30 seconds. Also test the fail close actuation of each damper on loss of power or instrument air supply.	3. Confirm by visual inspection that each Secondary Containment HVAC main supply and exhaust isolation damper closes in less than 30 seconds after receipt of each isolation signal.
4. Leakage through each Secondary Containment isolation damper is designed to be compatible with the Secondary Containment leakage requirements established for the Standby Gas Treatment System.	4. Inspect the damper position switch capability and verify each secondary containment isolation damper reaches the fully closed position when automatic closure actuation occurs.	4. Confirm by visual inspection the Secondary Containment isolation dampers and their position switches comply with regulation requirements calling for an acceptable secondary containment barrier when fully closed.
5. Secondary Containment HVAC System exhaust fans are designed to be started before the supply fans start and be stopped in the event the supply fans fail.	5. Inspect the configuration of the controls and test the interlock of the supply fans with the exhaust fans to verify the supply fans cannot be started before the exhaust fans are operating and upon failure of the exhaust fans, the supply fans stop automatically.	5. Confirm by visual inspection that the supply fans do not start before the exhaust fans are operating and the supply fans stop when the exhaust fans are not operating.

Table 2.15.5c: Reactor Building Heating, Ventilating And Air Conditioning (HVAC) System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. Secondary Containment Essential Equipment HVAC system configuration is shown on Figure 2.15.5c and consists of safety related room coolers in each of the following rooms: Residual Heat Removal (RHR) System's three pump and heat exchanger rooms, High Pressure Core Flooding(HPCF) System's two pump rooms, Reactor Core Injection Cooling (RCIC) System turbine driven pump room, Standby Gas Treatment System (SGTS) two fan rooms, Flammability Control System (FCS) two recombiner rooms, Fuel Pool Cooling (FPC) System's two pump rooms, and Containment Atmospheric Monitoring System (CAMS) two equipment rooms.	6. Inspect the configuration of the room coolers and verify their cooling coils are connected to the HVAC Emergency Cooling Water (HECW) System.	6. As-built Secondary Containment HVAC installation conforms to the design documentation and the configuration of the components as shown in Figure 2.15.5c. Confirm by visual inspection that each cooling unit starts when the equipment to be cooled starts or the space thermostat calls for cooling.
7. Reactor Building HVAC equipment is designed to Safety Class 3, Quality Group C, Seismic Category I requirements.	7. Review documentation of the installed equipment, instruments, ducts, piping and supports for compliance, and (if applicable) the Code Stamp on the hardware.	7. Confirm the system equipment is designed, fabricated, installed and tested in compliance with applicable codes and regulatory requirements.
8. Reactor Building HVAC safety related equipment room cooling units are powered from Class 1E Electrical Divisions 1, 2 or 3 and each unit is connected to the same electrical division as equipment served. Equipment Room cooling units are designed to start when the equipment served starts or the room thermostat calls for cooling.	8. Test each cooling unit fan to verify they are powered from the same Class 1E Electrical Division that serves the equipment being cooled. Visually inspect each cooling unit to verify the cooler starts when the equipment served starts or the space thermostat is calling for cooling.	8. Based on visual inspection of actual operational tests confirm independence of the three electrical divisions and verify equipment room cooling unit starts when equipment served starts. Confirm the room cooling unit will also start when the room thermostat calls for cooling.

Table 2.15.5c: Reactor Building Heating, Ventilating And Air Conditioning (HVAC) System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9. Exhaust fans are designed to remove smoke from the Reactor Building Secondary Containment Rooms in the event of a fire. Fire zone dampers are designed to close to pressurize all areas adjacent to the zone with the fire and enable the exhaust filter bypass dampers to be opened and the exhaust fans establish and maintain a negative pressure in the zone and remove the smoke.	9. Demonstrate and visually inspect the capability of each fire zone damper to be positioned, each Reactor Building air exhaust filter to be bypassed and the exhaust fans started from the Control Room or from the hand-off- automatic (H-O-A) switches in the motor control center (MCC) outside the Reactor Building and remove the smoke.	9. Confirm the Reactor Building HVAC fire zone dampers partially close, exhaust bypass dampers open and each exhaust fan is capable of being started from outside the Reactor Building and able to remove smoke from the Reactor Building compartments
10. The configuration of the Reactor Building Electrical Equipment HVAC System is shown in Figure 2.15.5d.	10. Inspections of the as-built HVAC System construction records shall be performed. Visual inspection of the configuration components shall be accomplished.	10. As-built Reactor Building Electrical Equipment HVAC installation conforms to the configuration shown in Figure 2.15.5d.
11. Three Reactor Building Electrical Equipment HVAC trains are mechanically and electrically independent.	11. Tests and visual inspection of the three independent trains will be conducted which will include independent and coincident operation of the three trains to demonstrate complete divisional separation.	11. As-built operational tests and visual inspection shall confirm independence of the three Class 1E Electrical Divisions 1.2 or 3.
12. Exhaust fan bypass dampers are designed to enhance smoke removal from the Reactor Building Electrical Equipment Rooms in the event of a fire inside these Reactor Building rooms. The exhaust fans are designed to remove smoke from the Diesel Day Tank Rooms and the Diesel Generator Rooms.	12. Demonstrate and visually inspect the capability of each exhaust fan bypass damper to open, return air damper to close and the exhaust fans to be stopped from the Control Room or aligned and positioned from outside the Reactor Building Electrical Equipment Rooms with their hand-off-automatic (H-O-A) switches on the motor control center to remove smoke from these Reactor Building Rooms. Demonstrate the capability of the exhaust fans to remove smoke from the Diesel Day Tank Rooms and the Diesel Generator Rooms.	12. Confirm by visual inspection the Reactor Building Electrical Equipment Rooms' exhaust fan bypass dampers are capable of being opened, return air dampers closed and the exhaust fans stopped from the Control Room or aligned and operated from outside the Reactor Building Electrical Equipment Rooms to remove smoke from the Electrical Equipment Rooms. Also confirm by inspection that the exhaust fans are also capable of removing smoke from the Diesel Day Tank Rooms and the Diesel Engine Rooms.

Table 2.15.5c: Reactor Building Heating, Ventilating And Air Conditioning (HVAC) System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
13. DG Emergency Supply Fans are safety related and are designed to provide additional diesel generator room cooling when the diesel is operating and also remove smoke from the Diesel Generator Room in the event of fire.	13. Inspections of the as-built HVAC System shall determine that one DG Emergency Supply Fan is controlled to start when the diesel engine starts, and the second fan starts when the room thermostat calls for additional cooling. High and low temperature alarms in the Control Room when the temperature is high. Both fans can be manually controlled, locally or from the Control Room. In the event of a fire these fans can also remove smoke from the Diesel Generator Room	13. As-built Reactor Building DG Emergency Supply Fan installation conforms to the design documentation and visual inspection shall confirm the controls will start one of the two fans when the diesel engine is started or start the second fan when the room thermostat calls for additional cooling. Also confirm these fans can remove smoke from the Diesel Generator Room.
14. Reactor Building non-safety related RIP Panel and Power Supply Rooms are designed to be cooled by the RIP HVAC dual fan recirculating air system with cooling coils served from the HVAC normal cooling water (HNCW) system as configured on Figure 2-15-5e. This is in addition to the supply and return/exhaust air cooling and smoke removal provided by the Electrical Equipment HVAC System configured on Figure 2.15.5d.	14. Inspections of the as-built RIP HVAC System construction records shall be performed. Visual inspection of the configuration components shall be accomplished.	14. As-built Reactor Building RIP Panel and Power Supply Rooms RIP HVAC installation conforms to the configuration shown in Figure 2.15.5e.

Table 2.15.5d: Turbine Building Heating, Ventilating and Air Conditioning (HVAC) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Turbine Building HVAC System is shown in Figures 2.15.5f and 2.15.5g.	1. Inspections of the as-built HVAC System construction records shall be performed. Visual inspection of the configuration components shall be accomplished.	1. As-built Turbine Building HVAC installation conforms to the configuration shown in Figures 2.15.5f and 2.15.5g.
2. Exhaust fans and roof power ventilators are designed to remove smoke from the Turbine Building rooms in the event of a fire. Fire zone dampers are designed to pressurize all areas adjacent to the zone with the fire and enable the exhaust filter bypass dampers to be opened and the exhaust fans and roof power ventilators started to establish and maintain a negative pressure in the zone and remove the smoke.	2. Demonstrate and visually inspect the capability of each fire zone damper to partially close and each Turbine Building air exhaust filter to be bypassed and the exhaust fans started from the Control Room or from the hand-off- automatic (H-O-A) switches in the motor control center (MCC) outside the Turbine Building fire zone and remove the smoke.	2. Confirm the Turbine Building HVAC fire zone dampers partially close and pressurize the areas adjacent to the zone with the fire, the exhaust filter bypass dampers open and each exhaust fan is capable of being started from outside the Turbine Building fire zone and able to remove smoke.
3. The Turbine Building Compartment Exhaust System is designed to establish and maintain a negative pressure in rooms with potential airborne radioactivity. Adjacent areas are pressurized to move air from clean areas to potentially contaminated areas. Refer to Table 3.2b Ventilation and Airborne Monitoring.	2. Demonstrate and visually inspect the performance of the Turbine Building Compartment Exhaust System to create a negative pressure in the rooms having the potential for radioactive contamination and observe the movement of air from the pressurized clean areas to the potentially contaminated rooms.	3. Confirm that the Turbine Building Compartment Exhaust System has the capability to maintain a negative pressure in the rooms having the potential for airborne radioactive contamination. Verify by visual inspection the movement of air from clean areas to potentially contaminated rooms.
4. The Turbine Building Lube Oil Exhaust System is designed to remove oil vapors from lube oil reservoir, condenser and pump rooms.	4. Visually inspect the lube oil exhaust system to demonstrate it maintains a negative pressure in the lube oil condenser and pump room and the room housing the lube oil reservoir.	4. Confirm that the Turbine Building Lube Oil Exhaust System actually maintains a negative pressure in the lube oil condenser and pump room and the room housing the lube oil reservoir.
5. Various Turbine Building spaces are provided with supplemental fan coil cooling units with coils connected to the HVAC Normal Cooling Water System. Space thermostats control the cooling water flow valves.	5. Visually inspect the supplemental fan coil units to verify their operation and control.	5. Confirm that the Turbine Building supplemental cooling units are capable of removing operating equipment heat releases to the spaces and are controlled by space thermostats.

Table 2.15.5e: Electrical Building Heating, Ventilating and Air Conditioning (HVAC) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Electrical Building HVAC System is shown in Figure 2.15.5h. The equipment in this building is not safety related.	1. Inspections of the as-built HVAC System construction records shall be performed. Visual inspection of the configuration components shall be accomplished.	1. As-built Electrical Building HVAC installation conforms to the configuration shown in Figure 2.15.5h.
2. Fan coil cooling units supplement the equipment room cooling with coils connected to the HVAC Normal Cooling Water System. Room thermostats control the cooling water flow control valves.	2. Visually inspect the supplemental fan coil units to verify their operation and control.	2. Confirm that the Electrical Building supplemental cooling units are capable of removing operating equipment heat releases to the spaces and are controlled by space thermostats.
3. Smoke removal is accomplished by closing the return air damper and circulating all outdoor air within the Electrical Building spaces. The Heating Boiler Room and the Combustion Turbine Generator Room are normally maintained at a negative pressure relative to the remaining equipment rooms maintained at a positive pressure. Equipment rooms are designed with zone fire dampers in their exhaust ducts to increase the pressurization when the fire is in an adjacent area.	3. Visually inspect the damper alignment to utilize all outdoor air and adjacent room pressurization to accomplish smoke removal. Demonstrate the capability to start each exhaust fan and align the dampers for smoke removal locally or from the hand-off-automatic (H-O-A) switches at each of the motor control centers.	3. Confirm by visual inspection that all supply and exhaust fans can be started from local or remote panels. Also confirm the return air dampers can be closed and the fire zone dampers positioned to accomplish pressurization in the areas adjacent to a fire. Verify that the Heating Boiler Room and the Combustion Turbine Generator Room is maintained at a negative pressure relative to the adjacent equipment rooms which are maintained at a positive pressure.

Table 2.15.5f: Service Building Heating, Ventilating and Air Conditioning (HVAC) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Service building HVAC System is shown in Figure 2.15.5i. The HVAC equipment in this building is not safety related.	1. Inspections of the as-built HVAC System construction records shall be performed. Visual inspection of the configuration components shall be accomplished.	1. As-built Service Building HVAC installation conforms to the configuration shown in Figure 2.15.5i.
2. The Service Building HVAC System consists of two trains, one serving the non-radioactive controlled areas and the other serving the radioactive controlled areas. The non-radioactive controlled areas are pressurized by redundant supply fans. The radioactive controlled areas are maintained at a negative pressure by redundant supply and exhaust fans to insure that air moves from the clean areas to the potentially contaminated areas. Refer to Table 3.2b Ventilation and Airborne Monitoring.	2. Visually inspect the equipment serving each area and demonstrate that air moves from the clean areas to the potentially contaminated areas. Demonstrate that the flow controls and low flow alarm are functioning to maintain the radioactive controlled area at a negative pressure as the pressure drop across the exhaust filters increase with time.	2. Visually confirm that air moves from the clean areas toward the potentially contaminated areas. Confirm that the HVAC equipment and flow control serving the radioactive controlled areas establishes and maintains a negative pressure relative to the environment. Confirm that the non-radioactive controlled areas are pressurized.
3. Smoke removal is accomplished by closing the non-radioactive controlled area return air damper and positioning the fire zone damper in the exhaust duct to pressurize the area. The radioactive controlled area exhaust fans remove smoke from both the clean areas and the potentially contaminated areas.	3. Inspect and visually demonstrate the return air damper can be closed and the radioactive controlled area fire zone damper can be positioned to pressurize the non-radioactive controlled areas. The exhaust fans of the radioactive controlled areas can be started locally or from their hand-off-automatic (H-O-A) switches on the motor control center to remove smoke from all areas of the Service Building.	3. Visually confirm that for smoke removal the return air damper closes, the fire zone damper is positioned to pressurize the non-radioactive controlled areas and the radioactive controlled area redundant exhaust fans start from the local panel or the H-O-A switches on the motor control center. Verify that smoke is removed from all areas of the Service Building.

Table 2.15.5g: Radwaste Building Heating, Ventilating and Air Conditioning (HVAC) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Radwaste building HVAC System is shown in Figure 2.15.5j. The HVAC equipment in this building is not safety related.	1. Inspections of the as-built HVAC System construction records shall be performed. Visual inspection of the configuration components shall be accomplished.	1. As-built Radwaste Building HVAC installation conforms to the configuration shown in Figure 2.15.5j.
2. The Radwaste Building HVAC System consists of a dual fan supply unit with bag filters and cooling coil connected to the HVAC Normal Cooling Water System. The radioactive controlled areas are maintained at a negative pressure by redundant exhaust fans to insure that air moves from the clean areas to the potentially contaminated areas. The Radwaste Control Room is maintained at a positive pressure with volume control on the room's redundant exhaust fans. Refer to Table 3.2b Ventilation and Airborne Monitoring.	2. Visually inspect the equipment serving each area and demonstrate that air moves from the clean areas to the potentially contaminated areas. Demonstrate that the flow controls function to maintain the Radwaste Control Room at a positive pressure.	2. Visually confirm that air moves from the clean areas toward the potentially contaminated areas. Confirm that the Radwaste Control Room flow control establishes and maintains a positive pressure relative to the environment and confirm that the potentially radioactive areas are maintained at a negative pressure.
3. Smoke removal is accomplished by opening the exhaust fan bypass damper to enable the dual supply fans to be started to pressurize all areas and remove smoke from the Radwaste Building. The supply and exhaust fans can be controlled from the Radwaste Control Room panel or the hand-off- automatic switches in the motor control center.	3. Inspect and visually demonstrate the exhaust fan bypass damper can be opened, the exhaust fans stopped and both supply fans started from the Radwaste Control Room panel or from the hand-off-automatic (H_O_A) switches in the motor control center. Both exhaust fans of the Radwaste Control room can be started locally or from their hand-off-automatic (H-O-A) switches on the motor control center to remove smoke from all areas of the Radwaste Building.	3. Visually confirm that for smoke removal the exhaust fan bypass damper opens, the exhaust fans stop and both supply fans start when their controls are actuated from the Radwaste Control Room panel or the H-O-A switches on the motor control center to remove smoke from the Radwaste Building. Similarly confirm that the Radwaste Control Room exhaust fans can both be started to remove smoke from the Radwaste Building

Table 2.15.5g: Radwaste Building Heating, Ventilating and Air Conditioning (HVAC) System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4. Radwaste Building Tank Exhaust System is designed to control air released from tanks being filled and permit this air to be drawn into tanks being simultaneously pumped out or being drained. Excess air is passed through a bag filter before the tank exhaust fan discharges it along with Radwaste Building exhaust to the stack.	4. Inspect and visually determine that the Radwaste Building Tank Exhaust System limits the release of tank air to the Radwaste Building Exhaust System and the stack.	4. Confirm that the Radwaste Building Tank Exhaust System controls the release of tank air and filters it before the tank exhaust is discharged to the stack. Verify the exhaust air is monitored for radioactivity before it is discharged to the stack.
5. Radwaste Building Incinerator Exhaust is designed to be treated by cooling the gas and passing it through a HEPA filter and fan before release to the stack.	5. Inspect and visually determine the Radwaste Building Incinerator System functions to cool the exhaust gas before passing it through a HEPA filter and fan to the stack.	5. Confirm the Incinerator exhaust gas is cooled and passes through a HEPA filter and fan before the gas is discharged to the stack.

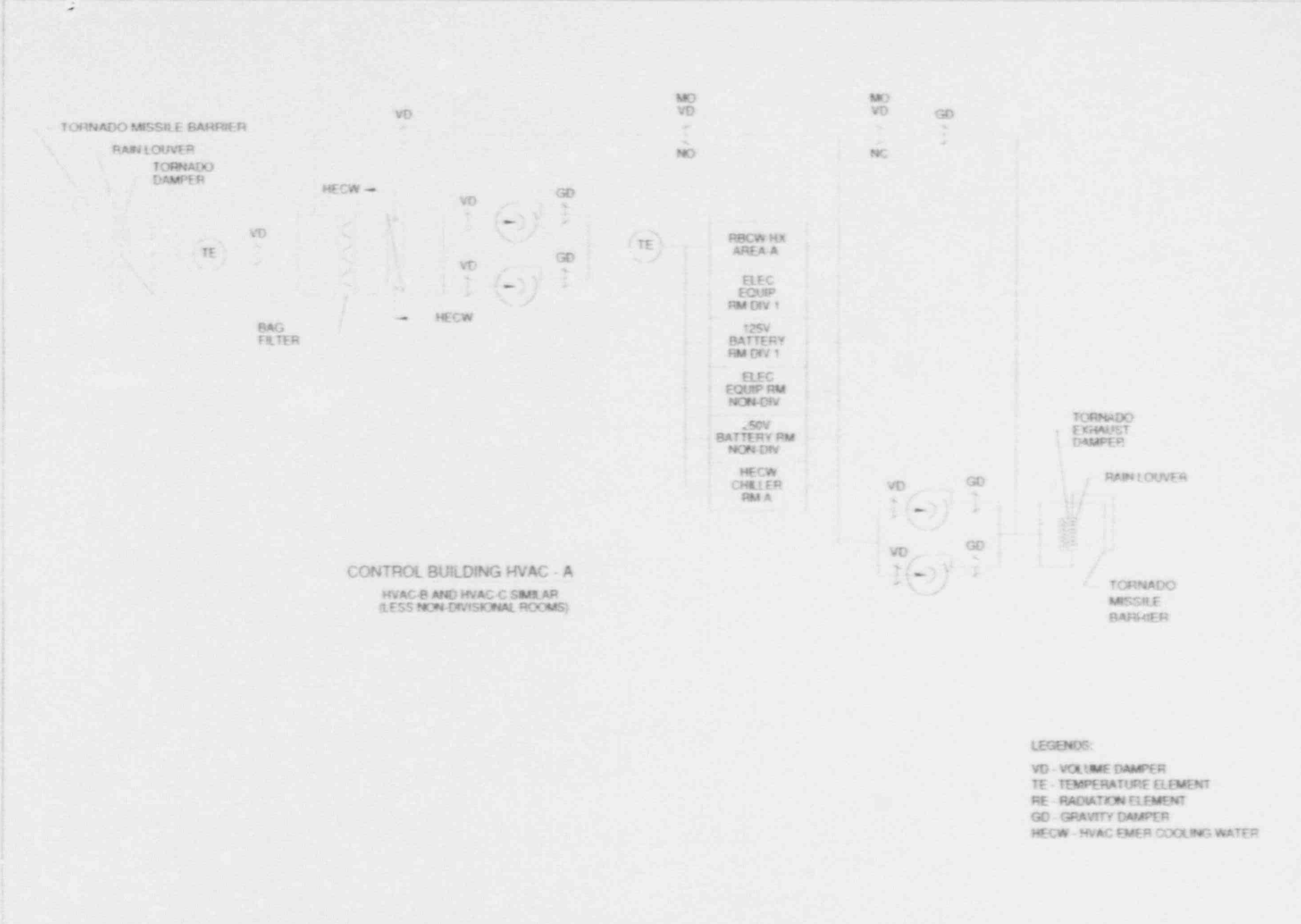


Figure 2.15.5a Control Building HVAC System

Figure 2.15.5b Control Room and Habitability Area HVAC System

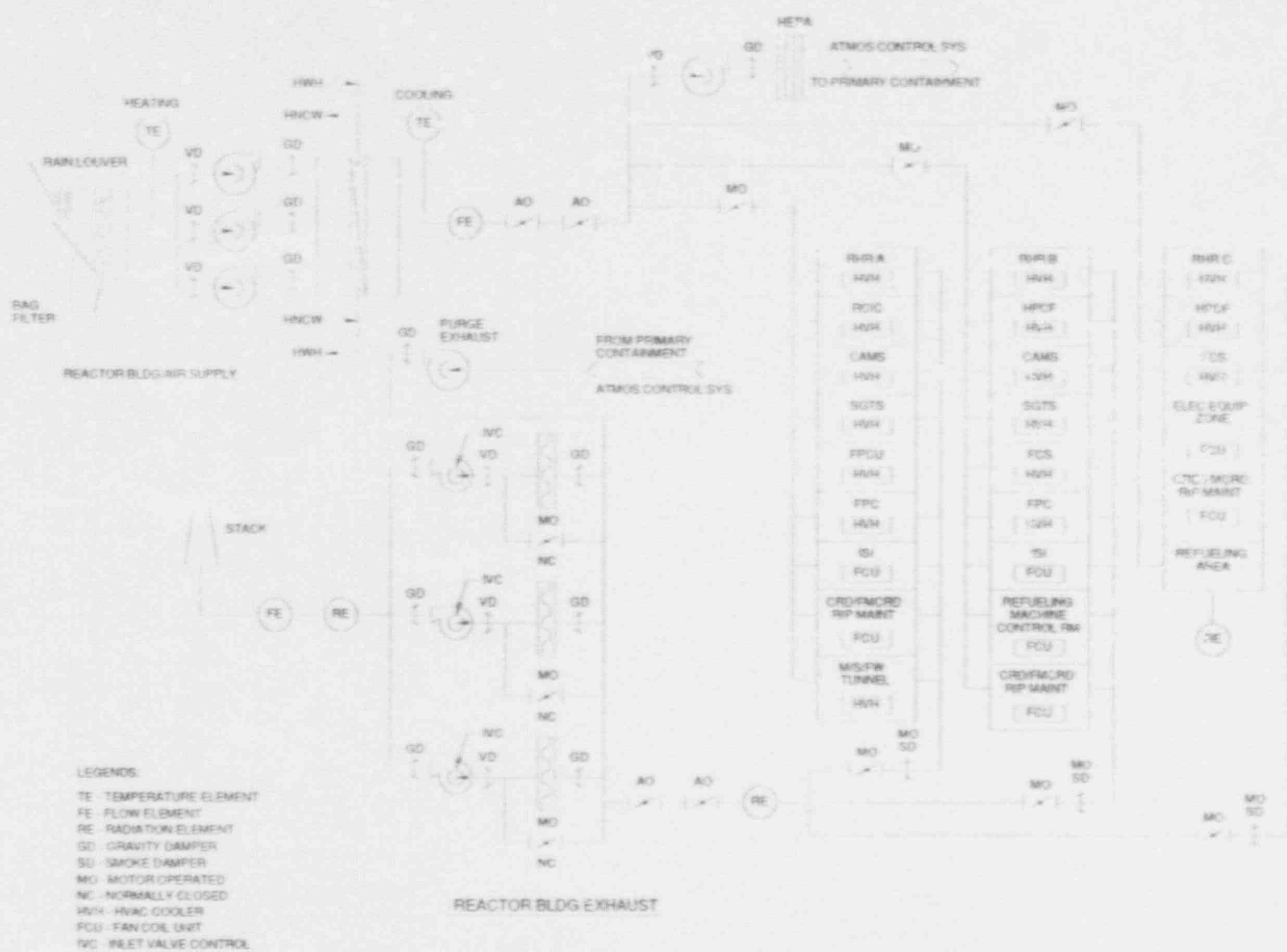


Figure 2.15.5c Reactor Building Secondary Containment HVAC System

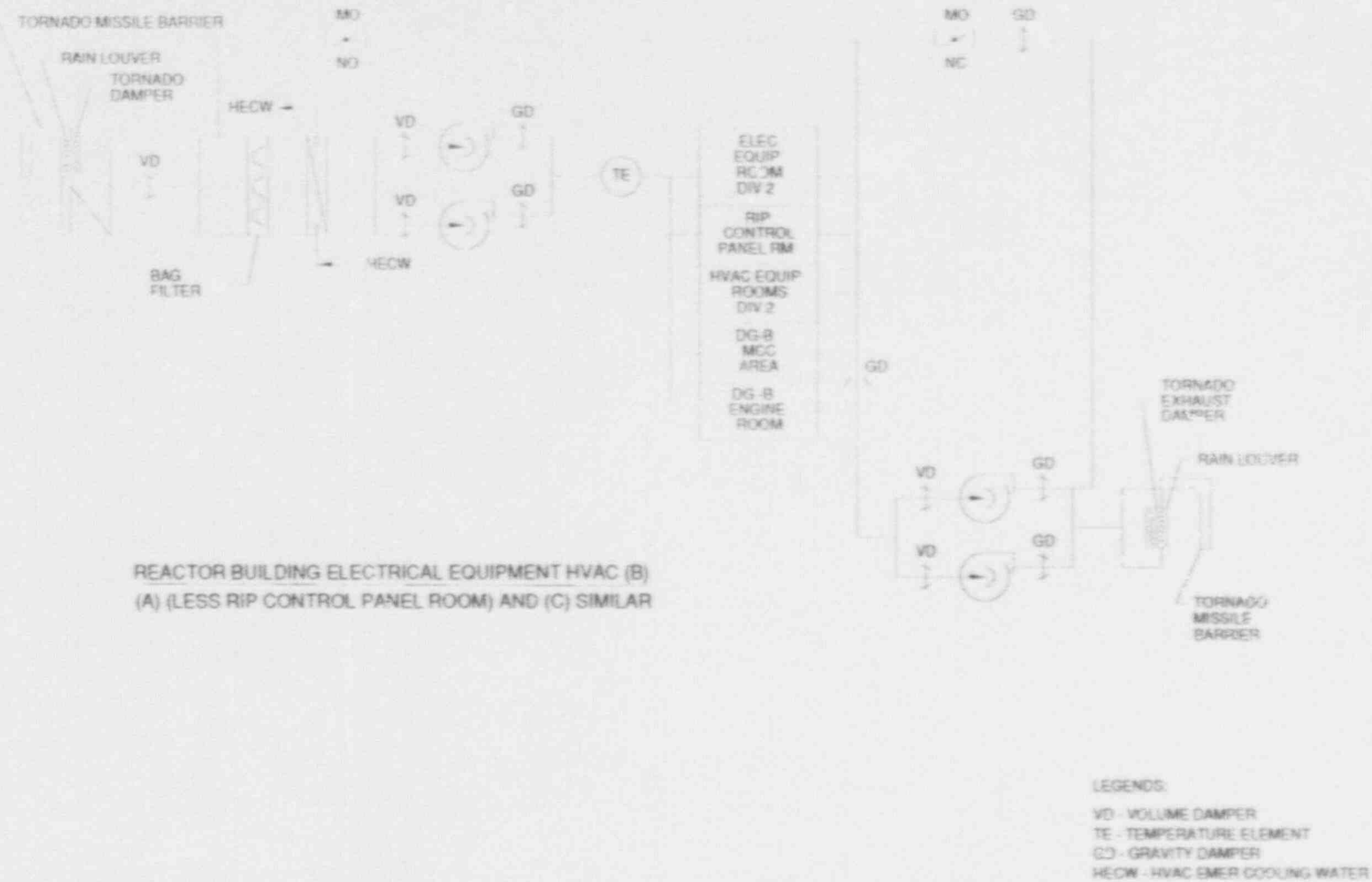


Figure 2.15.5d Reactor Building Electrical Equipment HVAC System

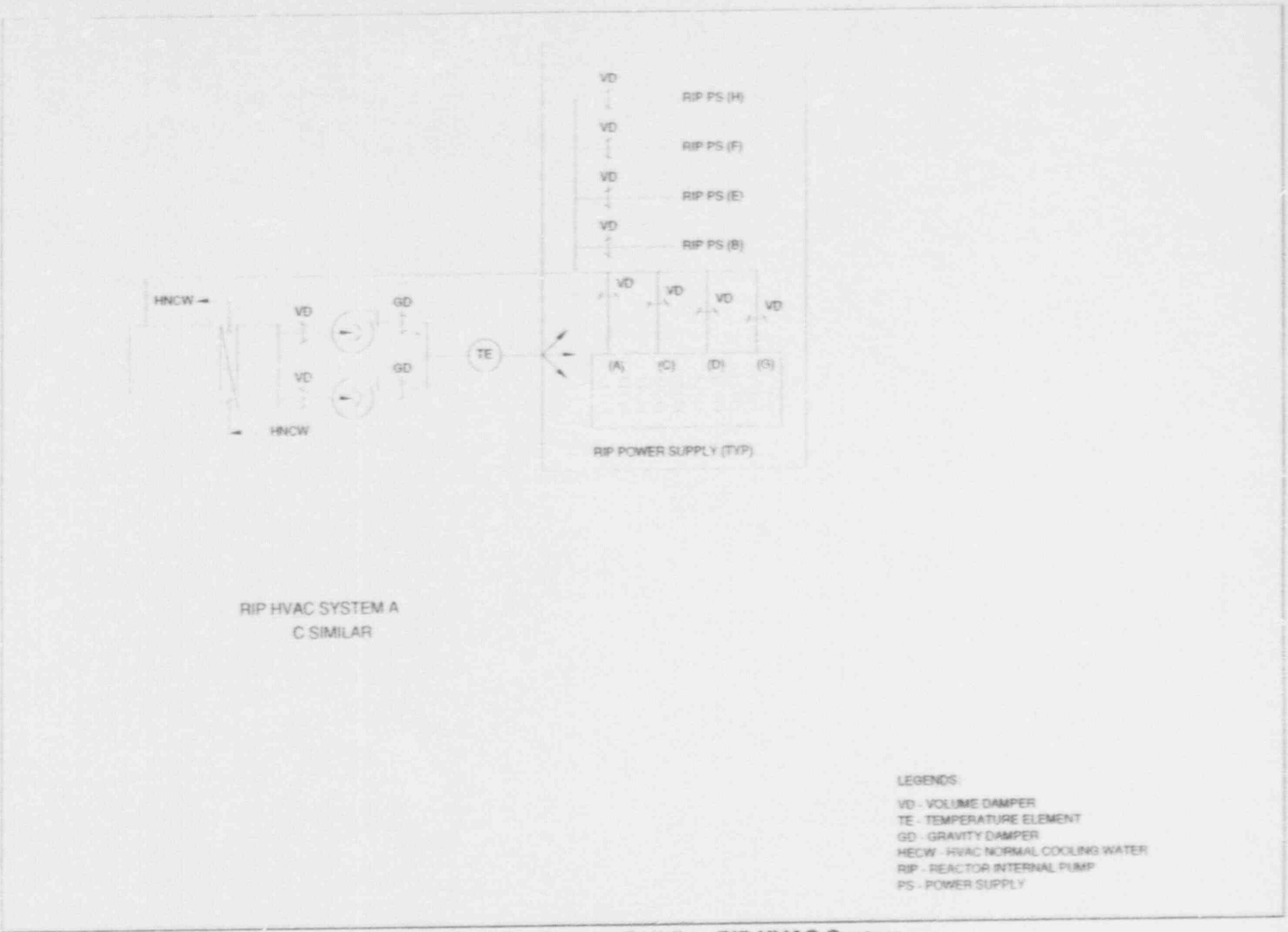


Figure 2.15.5e Reactor Building RIP HVAC System

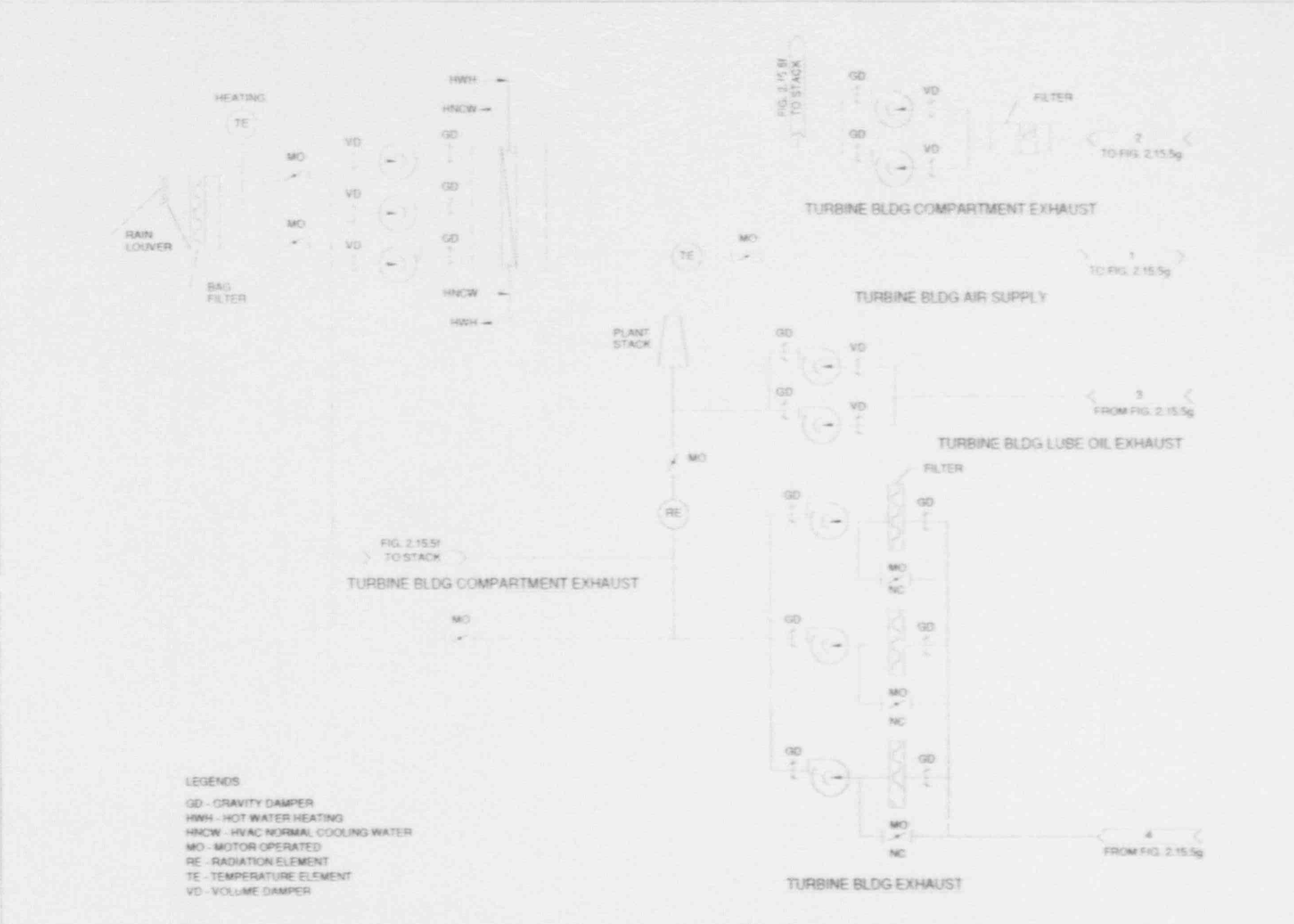


Figure 2.15.5f Turbine Building HVAC System

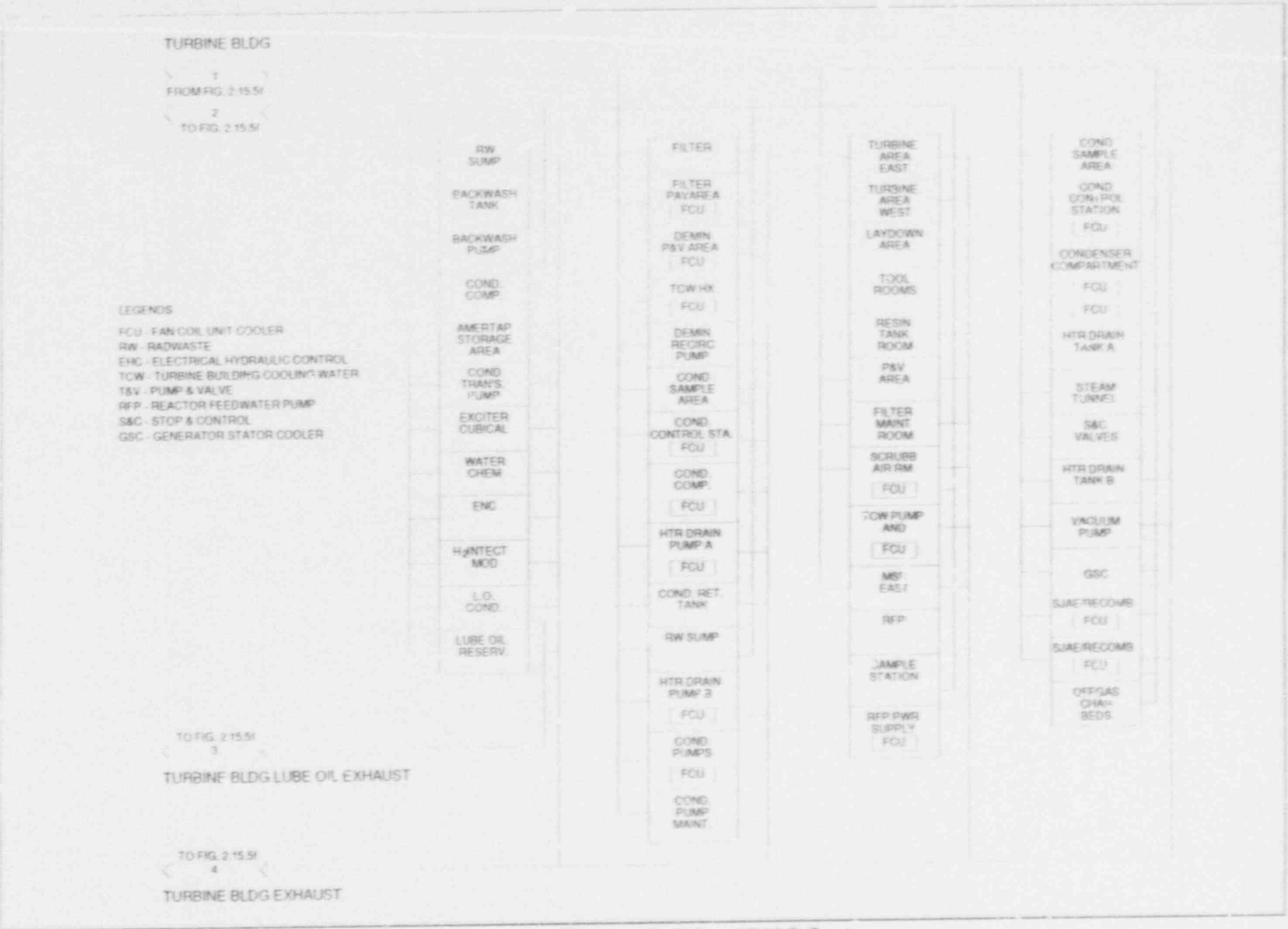


Figure 2.15.5g Turbine Building HVAC System

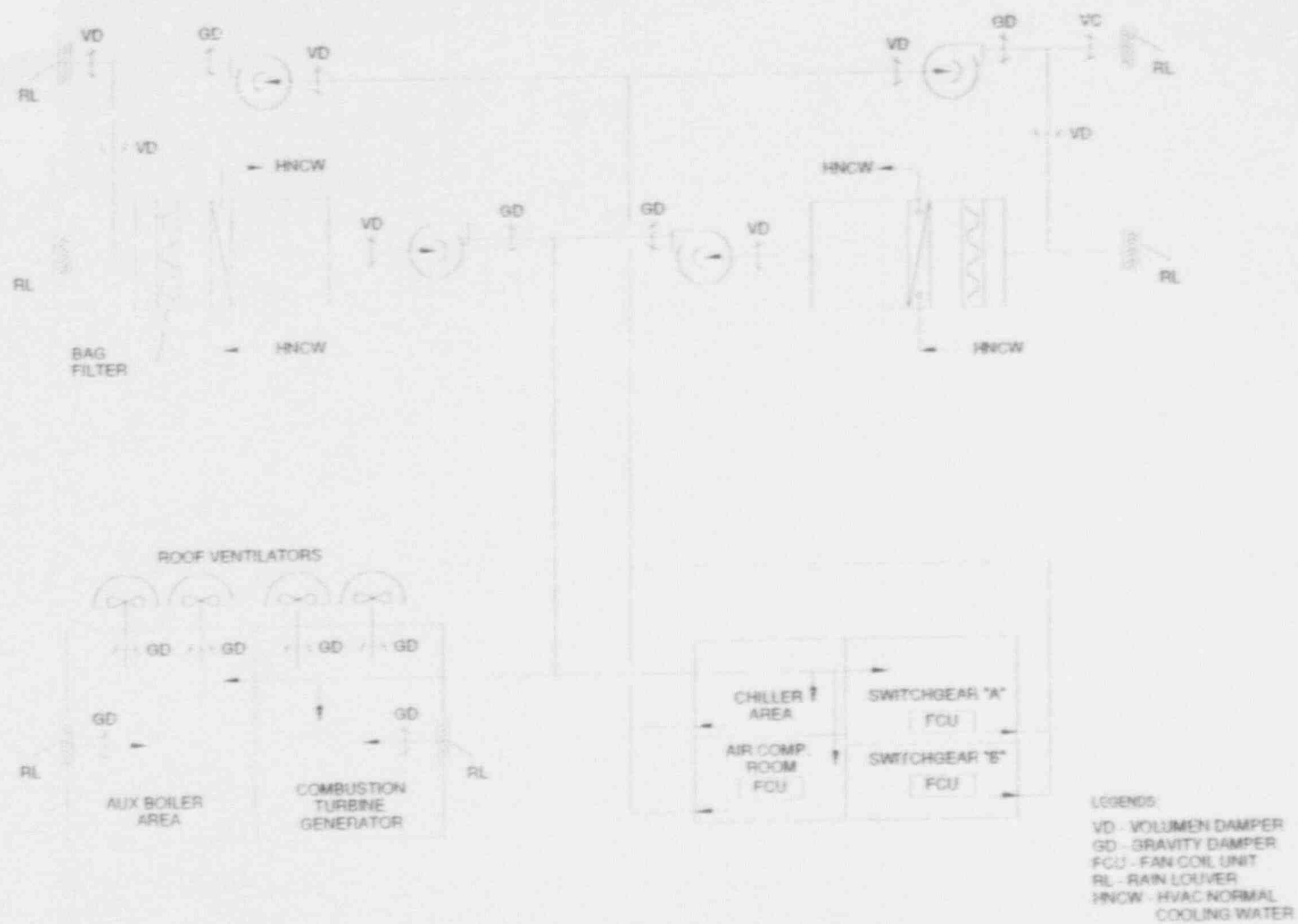


Figure 2.15.5h Turbine/Electrical Building HVAC System

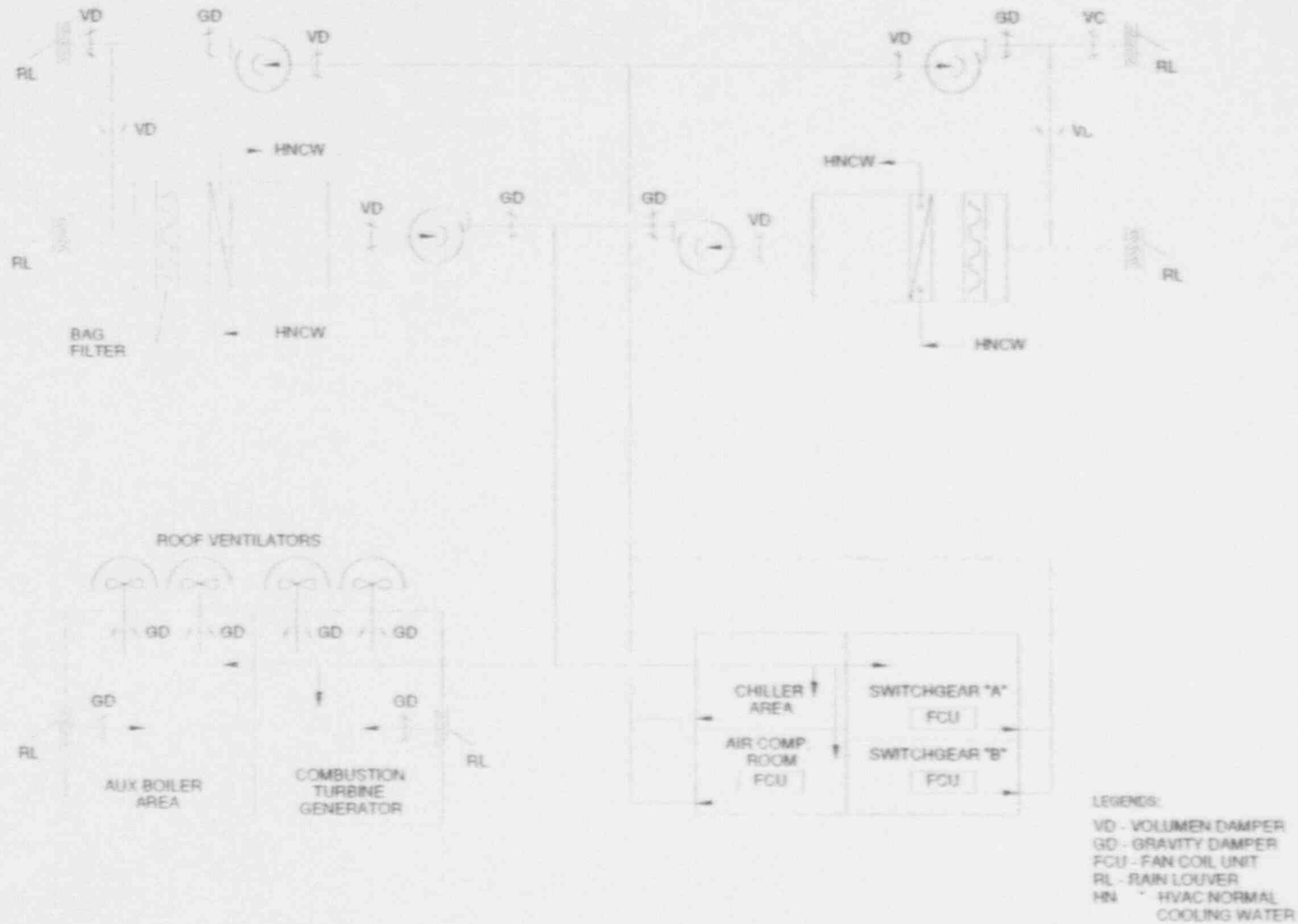


Figure 2.15.5h Turbine/Electrical Building HVAC System

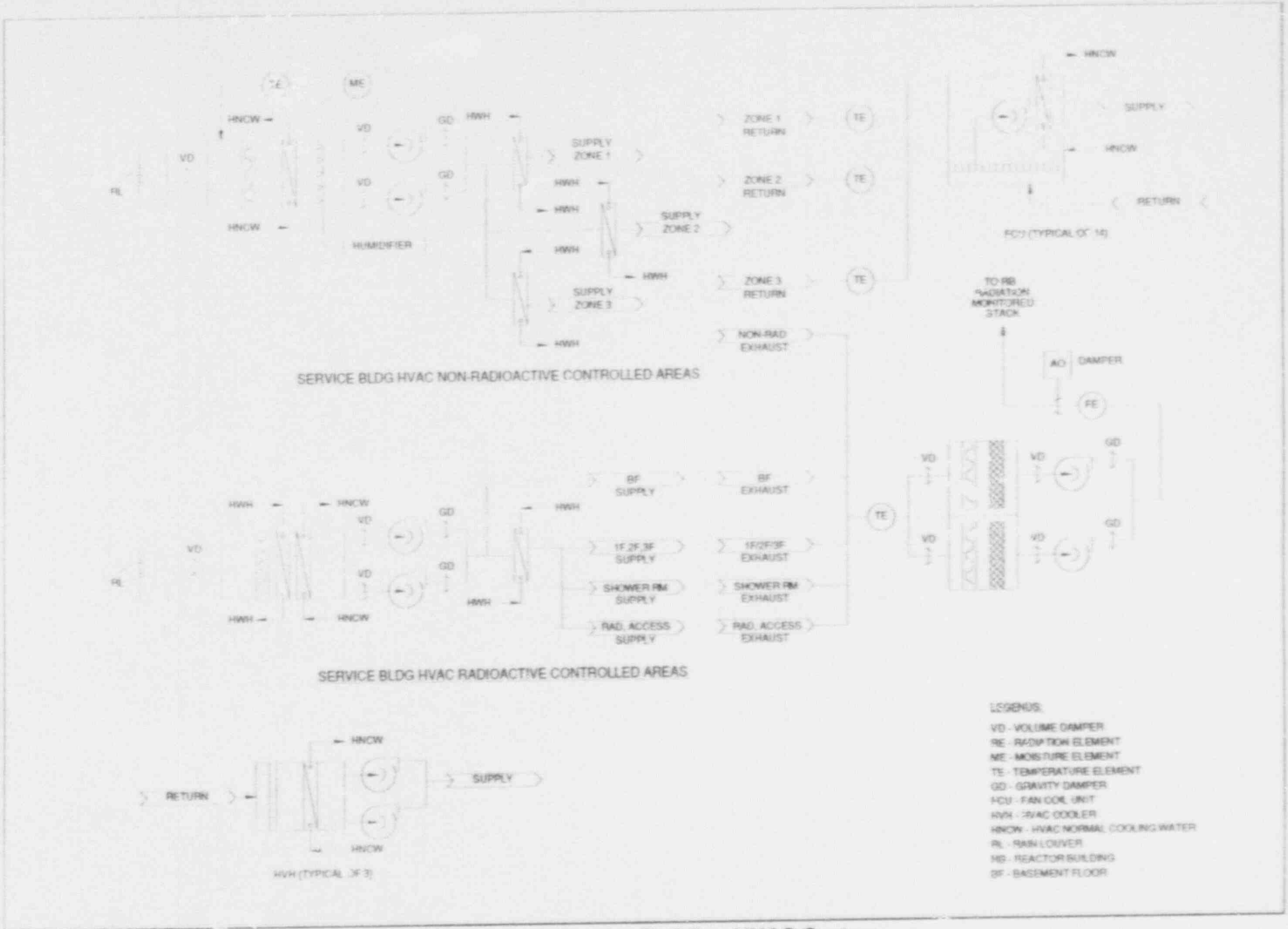


Figure 2.15.5i Service Building HVAC System

2.15.6 Fire Protection System

Design Description

The Fire Protection System program's intent is to provide a "defense-in-depth" d gn resulting an adequate balance on:

(1) Preventing fires from starting;

(2) Quickly detecting and extinguishing fires that occur, thus limiting fire damage; and

(3) Designing safety-related systems so that a fire that starts in spite of the fire prevention program and burns out of control for a considerable length of time will not prevent safe shutdown.

In addition, fire protection systems are designed so that their inadvertent operation of the occurrence of a single failure in any of these systems will not prevent plant safe shutdown.

Primary suppression coverage for all buildings with safety-related equipment is provided by wet standpipes and hose reels with electrically safe nozzles. Secondary coverage is provided by portable fire extinguishers.

The sprir r systems in the reactor building and the wet standpipe systems in the reactor and control buildings are designed and ana'yzed to remain functional following a safe shutdown earthquake. A portion of the water supply system including a tank, a pump and part of the yard supply main are designed to these requirements also. The remainder of the water systems are designed to the appropriate fire protection standards. During normal operation the seismically designed and non-seismically designed systems are separated by normally closed valves and a check valve such that a break in the non-seismically analyzed portion of the system cannot impair the operation of the seismically designed portion of the system. See the system drawings, Figures 2.15.6a and 2.15.6b for more detailed requirements and information for these systems.

The water supply system is required to be a fresh water system, filtered if necessary to remove silt and debris. Two sources with a minimum capacity of 300,000 gallons for each source is provided. If the primary source is a volume limited supply such as a tank, a minimum of 20,000 gallons must be passively reserved for use by the seismically designed portion of the suppression system. This reserve will supply two manual hose reels for 2 hours. A motor driven pump is in the train designed to remain functional following the safe shutdown earthquake. Its power is supplied from a non-class 1E bus which is fed by one of the diesel generators. A jockey pump to keep the system pressurized is provided. The fire water requirement for the reactor building is 1500 gpm at 125 psig which will meet the standpipe flow requirement of [illegible] gpm at 65 psig at the most distant or highest standpipe.

The turbine building is provided with standpipes, hose reels and portable extinguishers throughout the building. In addition, the following fire suppression systems provide primary fire suppression capability to the following areas:

(1) Automatic closed head sprinkler systems are provided in the open grating area of the three floors under the turbine.

(2) Deluge foam-water sprinkler systems are provided in the lube oil conditioning area and the lube oil reservoir area.

(3) A deluge sprinkler system is provided in the hydrogen seal oil unit area.

(4) A preaction sprinkler system is provided in the auxiliary boiler area.

The turbine building fire suppression systems receive water from the portion of the supply system which is not required to be seismically analyzed for safe shutdown earthquake.

The main power, unit auxiliary and reserve transformers are provided with deluge water spray suppression systems. The systems are automatically actuated by flame or temperature detectors. An oil and water collection pit is provided beneath each transformer. Drains away from buildings and transformers are provided for each pit. Shadow type fire barrier walls are provided between adjacent transformers. A closed head sprinkler system is provided for the truck entry area of the reactor building. An automatic foam sprinkling system is provided for the diesel generator and day tank rooms.

Fire detection for all areas, except the diesel-generator rooms is provided by ionization-type product of combustion systems reporting to satellite panels which in turn report to the master panel located in the control equipment room of the control building. Trouble and alarm signals are retransmitted to the control room. These detection systems are not seismically qualified, as they are passive and have no control functions.

The diesel-generator room fire detection systems utilize heat detectors and infrared detectors to initiate an automatic foam sprinkler extinguishing system. This detection system is seismically qualified to protect against inadvertent actuations. However, the DG equipment is designed to continue operation unless manually shut down by the operator.

Fire detection and suppression alarm systems have 4-hour battery packs located at each satellite panel and the control room panel and are provided with power from an uninterruptible power supply.

Standpipe and hose reel stations are equipped with 100-foot neoprene-lined hoses with electrical safe nozzles. The standpipe system is Seismic Category I and one train of the water supply system is designed to remain functional following a safe shutdown earthquake.

Automatic wet pipe sprinkler system piping is designed for pendant and upright sprinklers to a distance between the branch lines and between sprinklers on the branch lines that does not exceed 12 feet and a protection area per sprinkler that does not exceed 130 square feet. For sidewall sprinklers, the distance between sprinklers does not exceed 10 feet and the protection area per sprinkler does not exceed 100 square feet.

Automatic foam extinguishing systems are designed to meet a minimum allocation rate of 0.16 gpm per square foot. The duration of foam discharge shall be a minimum of 10 minutes. Audible and visual alarms are provided.

Portable fire extinguishers are provided throughout the buildings. Extinguishers are Class ABC multipurpose.

Distance from a hose reel and extinguishers is no more than 100 feet from any location. Manual fire alarm stations are provided for each hose Hose reels are located to provide double coverage for most areas of the

The smoke control system for the plant provides major features as follows:

(1) Venting of fire areas to prevent undue buildup of pressure due to a fire.

(2) Pressure control across the fire barriers to assure that any leakage is into the fire area experiencing the fire.

(3) Pressure control and purge air supply to prevent back flow of smoke and hot gases when opening fire barrier doors for access for manual fire suppression activities.

(4) Augmented and directed clean air supply to provide a clean air path to the fire for fire suppression personnel.

(5) Smoke control by fans and systems external to the area experiencing the fire.

(6) Removal of smoke and heat from the fire by fans operating to supply clean, cool air.

The systems whose primary functions are to provide core cooling to bring the plant to a safe shutdown condition have three indepen nt mechanical and electrical safety-related divisions (mechanical division A, B, C and electrical division 1, 2, 3). Each division is capable of bringing the plant to a safe shutdown condition whether the system is initiated manually or automatically. The plant layout and design is such that the redundant portions of safety-related systems are located in different fire areas, therefore, if one division becomes disabled due to a fire (complete burnout without recovery is acceptable) there are still two independent redundant divisions available to provide core cooling. The system initiation logic is located in the control room, and is made up of four logic, but if one division becomes disabled (e.g., due to a fire) the system initiation logic reverts to two out of the three logic. Sa e shutdown following a fire is assured due to the fact that the systems in any one of the three safety divisions are capable of accomplishing safe shutdown, and with the exceptions listed below the safety divisions are separated by three hour fire rated barriers.

(1) Main control room

All four logic divisions are present in the main control room. Alternate safe shutdown capability is provided f om the remote shutdown panel. The remote shutdown panel is located in a fire zone different from the main control room fire zone.

(2) Primary containment

All four logic divisions are present in the primary containment. Primary containment is inerted during operation so that a fire in containment is not credible. In spit of this, separation within containment is maintained by as much distance as possible.

(3) Special cases

There are some instances where equipment from more than one safety division is purposely mounted in the same fire area. For example, in orde, to provide redundancy for leak detection initiation, leak detection thermocouples for two or more divisions are mounted in the same room to control the single division of equipment contained in the room.

Even with these limited exceptions for separation by fire barriers, the plant design is such that complete burnout of a given fire area may occur and there will still be two divisions of functionally available equipment (including cables), either division of which is capable of accomplishing plant shutdown. Compliance o the design to this objective is confirmed by the fire hazard analysis.

The fire hazards analysis is performed on a room-by-room, system-by-system basis and includes a set of drawings which reflect pertinent details of construction, location of rooms and location of fire suppression equipment.

The basis of the overall plant design with respect to the effects of fire is to assume that all functions are lost for equipment, including electrical cables, located within an area experiencing a fire. Redundant equipment is provided in other fire areas. A fire area by fire area treatment for the fire hazard analysis evaluates the compliance of the design to this requirement for redundancy. Compliance is confirmed or the need for corrective action is identified and initiated to achieve compliance to the overall plant design basis. The most serious consequence of a fire is that it may incapacitate one safety or safe shutdown division. This is consistent with the single failure design criteria used throughout the plant. Regardless of the location of a fire, sufficient operable equipment is assured for use in safely shutting the plant down.

The fire hazard analysis assumes that the function of a piece of equipment may be lost if the equipment is either involved in fire fighting activities or subjected to fire suppression agents and confirms that redundant equipment out of the fire area is available. This redundant equipment is capable of performing the required safety or shutdown function. The basis of the design is not to assume a questionable limit on damage within a given fire area but to provide redundant equipment elsewhere.

The fire detection systems are Class A, and therefore are tolerant of single failures. The fire suppression systems are designed such that there are two suppression systems available to any given area. Areas covered by sprinklers or foam systems are also covered by the manual hose system. Areas covered by the manual hose system only may be reached from at least two hose stations. Standpipes are fed from two directions.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.15.6 provides a definition of the inspections, tests and/or analyses together with associated acceptance criteria which will be undertaken for the Fire Protection System.

Table 2.15.6 Fire Protection System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the fire protection water supply system and yard piping is shown in Figures 2.15.6a and 2.15.6b.	1. Inspection of the as-built fire water supply system and yard piping configuration shall be performed.	1. Verification of the as-built system is in conformance with the as-designed configuration (Figures 2.15.6.a and 2.15.6b).
2. The fire protection water system has one complete train composed of seismically-analysed components servicing the reactor building and control building.	2. Inspection of the as-built fire water system and seismic analysis documentation shall be performed.	2. Verification that one complete fire water system train complies with seismic analysis.
3. The motor driven pump in the seismically analysed train receives backup power from one of the diesel generators.	3. Inspection of the as-built system electrical power circuits and connections shall be performed.	3. Verification that motor driven pump is connected to non-Class 1B bus which is powered by diesel generator.
4. Two water tanks of 300,000 gallons minimum each are provided with one having a dedicated volume of 20,000 gallons for the seismically designed train.	4. Inspection of as-built storage water tanks and design documentation shall be performed.	4. Verification that storage tanks meet the capacity and suction orientation requirements.
5. Two fire water supply system pumps provide 1500 gpm flow each at a discharge pressure of 125 psig. Uppermost standpipe will have minimum flow of 500 gpm at nozzle pressure of 65 psig.	5. Vendor to conduct shop tests relating to pump performance. Field test after installation with temporary hoses and instrumentation shall be performed.	5. Verification of certified vendor documentation plus verification that pumps and uppermost standpipes meet flow and pressure requirements.
6. Automatic sprinkler system piping has a maximum of 12 ft. between sprinkler heads and branch lines for pendant and upright sprinklers and a maximum of 10 ft. for sidewall sprinklers.	6. Inspection of as-built automatic sprinkler systems and conformance to design documentation shall be performed plus flow testing of most distant nozzles.	6. Verification of maximum spacing meets 12 ft. and 10 ft. requirements plus verification of system operability.
7. Standpipe and hose reel stations are equipped with 100 ft. neoprene-lined hose. Hose reels are located to provide two-hose coverage.	7. Inspection of as-built hose reel locations and length of attached hose shall be performed.	7. Verification of 100 ft. length hoses at all reels and verification that no point is more than 100 ft. from any two hose reels.

Table 2.15.6: Fire Protection System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8. Automatic foam extinguishing systems are provided for the diesel generator and day tank rooms with a minimum discharge time of 10 minutes.	8. Inspection of as-built systems with design documentation along with field testing of systems.	8. Verification of system operability and minimum time requirement.
9. Portable fire extinguishers are provided as backup throughout the plant buildings with no more than 100 ft. distance to any one.	9. Inspection of as-built layout with design documentation shall be performed.	9. Verification of back-up fire extinguishers with ≤ 100 ft. to nearest one.
10. Manual and automatic alarms are provided as passive systems; no control of extinguishing functions.	10. Inspection and testing of as-built alarms along with design documentation shall be performed.	10. Verification that alarms function correctly, but without controlling any extinguishing function.
11. Two detection systems are provided in all safety-related areas.	11. Inspection and testing of as-built detectors shall be performed.	11. Verification that detectors function correctly and provide system actuation signals as required.
12. Two fire suppression systems are available to any given fire area.	12. Inspection of as-built plant along with design documentation shall be performed.	12. Verification that each fire area has at least two independent means of fire suppression.
13. Fire water supply connections are provided for backup water injection into the reactor vessel and into the drywell spray header from the seismically-qualified train.	13. Inspection of as-built piping layout with design drawings shall be performed. Analysis of flow rates for PRA conditions shall be performed.	13. Verification that piping layout meets requirements and that flow calculations meet PRA assumptions.
14. Provisions for control room alarms and indications of suppression system operation are provided.	14. Inspection and testing of as-built alarm and indication system shall be performed.	14. Verification of correct operation of alarms and indicators.
15. Three-hour fire barriers are incorporated to confine the direct effects of a fire to the fire area in which it originates.	15. Inspection of as-built plant along with design drawings shall be performed.	15. Verification that all fire areas are bounded by three-hour or equivalent boundaries.
16. Fire areas with combustible loading limits exceeding 64,000 BTU/ft^2 for non-electrical equipment rooms and 128,000 BTU/ft^2 for electrical equipment rooms are provided with an automatic fire suppression system.	16. Inspection of as-built plant and calculations of expected combustible loadings shall be performed.	16. Verification that fire areas with combustible loadings exceeding the requirements are serviced by an automatic fire suppression system.

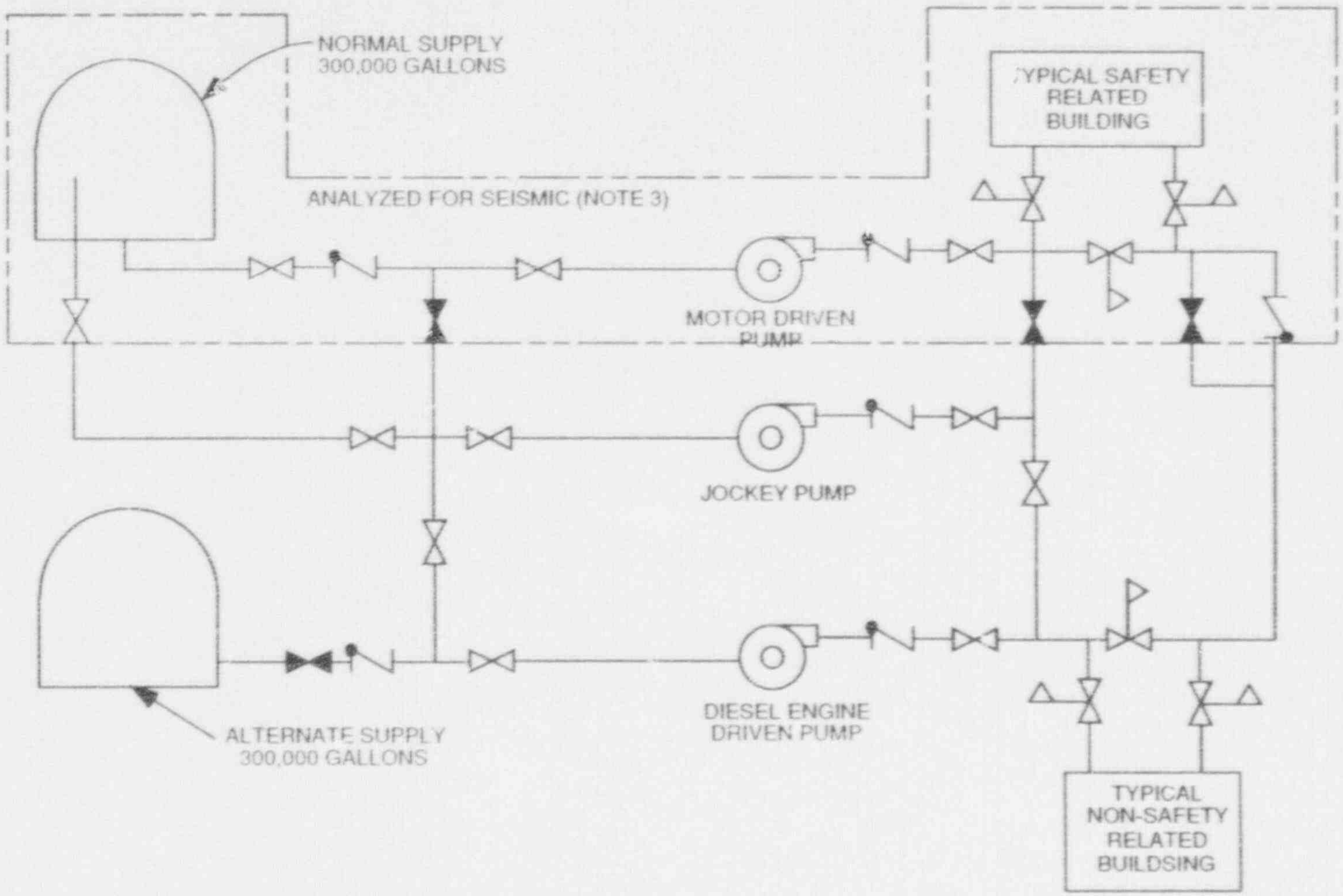
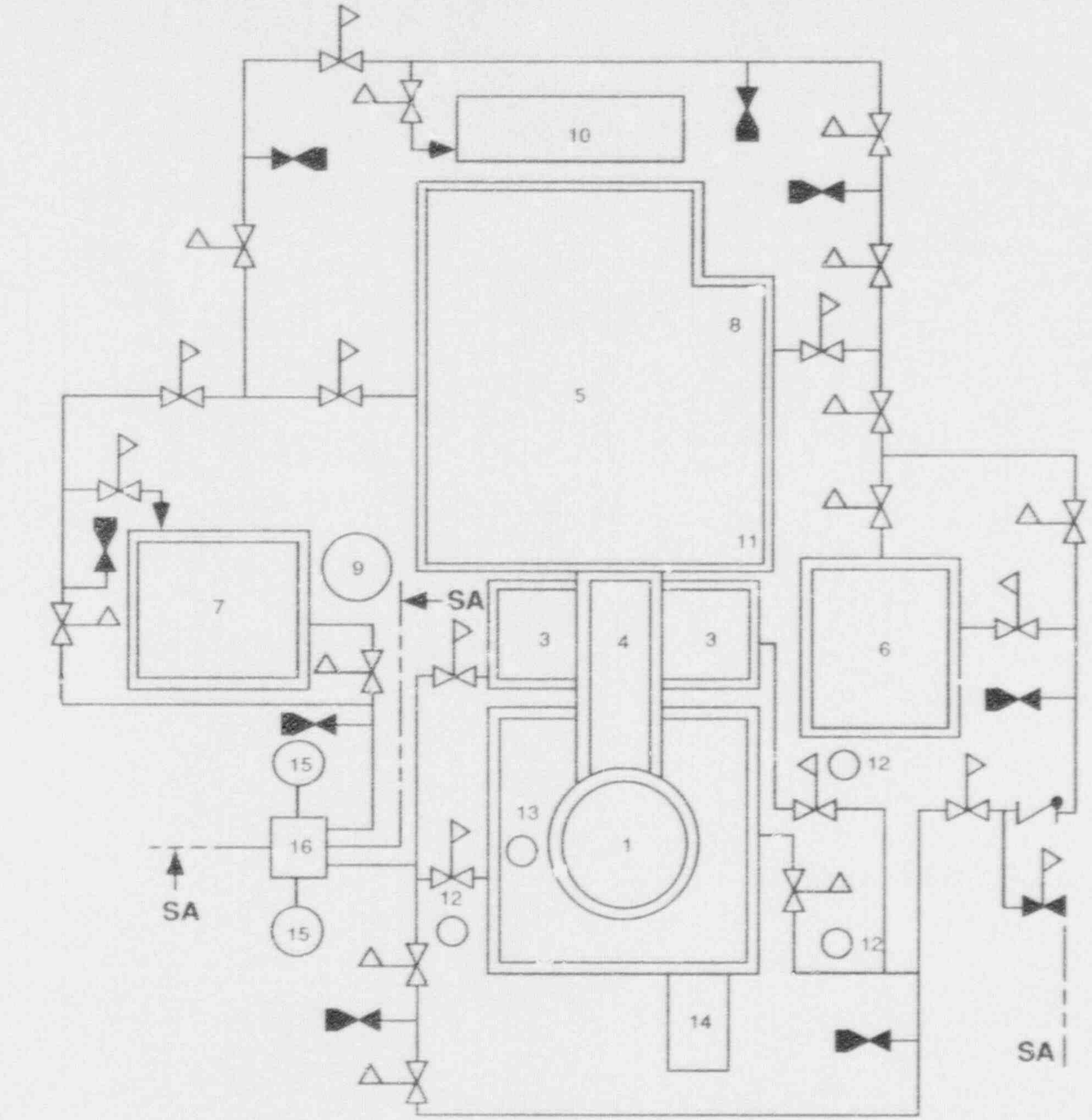


Figure 2.15.6a Fire Protection Water Supply System



NO.	FACILITY
1	REACTOR CONTAINMENT
2	REACTOR BUILDING
3	CONTROL BUILDING
4	MAIN STEAM/FEEDWATER TUNNEL
5	TURBINE BUILDING
6	SERVICE BUILDING
7	RADWASTE BUILDING
8	HOUSE BOILER
9	CONDENSATE STORAGE TANK
10	MAIN TRANSFORMER
11	NORMAL SWITCHGEAR
12	DIESEL OIL STORAGE TANK (3)
13	STACK
14	EQUIPMENT ENTRY LOCK
15	FIRE PROTECTION WATER STORAGE TANK (2)
16	FIRE PROTECTION PUMPHOUSE

POST INDICATOR VALVE

FIRE HYDRANT & SHUTOFF VALVE

SA SEISMIC ANALYSIS FOR SAFE SHUTDOWN EARTHQUAKE

Figure 2.15.6b Fire Protection Yard Main Piping

2.15.7 Floor Leakage Detection System

Design Description

The site-specific drainage system is also used to detect abnormal leakage in safety-related equipment rooms and the fuel transfer area.

Inspections, Tests, Analyses and Acceptance Criteria

No entries for this system.

2.15.8 Vacuum Sweep System

Design Description

A portable, submersible-type, underwater vacuum cleaner is provided to assist in removing crud and miscellaneous particulate matter from the pool floors or reactor vessel. The pump and the filter unit are completely submersible for extended periods. The filter "package" is capable of being remotely changed, and the filters will fit into a standard shipping container for offsite burial.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.15.8 provides definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the Vacuum Sweep System.

Table 2.15.8: Vacuum Sweep System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analysis	Acceptance Criteria
1. The vacuum pump and the filter unit are capable of being completely submersed for extended periods.	1. Procurement documentation will be reviewed to evaluate the capability of the pump and filter unit to operate under water.	1. Confirmation that the pump and filter unit is capable of operating under water.
2. The filter "package" is capable of being remotely changed.	2. Testing will be conducted involving replacement of the filter "package" remotely.	2. Confirmation that the filter "package" can be replaced remotely.

2.15.9 Decontamination System

Design Description

The Decontamination System provides areas, equipment, and services to support low radiation level decontamination activities. The services may include electrical power, service air, demineralized water, condensate water, radioactive and nonradioactive drains, HVAC, and portable shielding.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.15.9 provides definition of the inspections, and/or analyses, together with associated acceptance criteria which will be undertaken for the Decontamination System.

Table 2.15.9: Decontamination System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analysis	Acceptance Criteria
1. Areas are provided for low level decontamination activities and is supplied with electric power, service air, demineralized water, condensate water, radioactive and nonradioactive drains, HVAC, and portable shielding.	1. Visual inspection to verify that the certified design commitment is met.	1. Confirmation that the certified design commitment is met.

2.15.10 Reactor Building

Design Description

The Reactor Building (RB) is constructed of reinforced concrete with a steel frame roof. The RB has four stories above the ground level and three stories below. Its shape is a rectangle of approximately 59 meters in 90-270 deg. direction; approximately 56 meters in the 0-180 deg. direction, and a height of about 58 meters from the top of the basemat.

The Reinforced Concrete Containment Vessel (RCCV) in the center of the RB encloses the Reactor Pressure Vessel (RPV). The RCCV supports the upper pool and is integrated with the RB structure from the basemat up through the elevation of the RCCV top slab. The interior floors of the RB are also integrated with the RCCV wall. The RB has slabs and beams which join the exterior wall. Columns support the floor slabs and beams. The fuel pool girders are integrated with the RCCV top slab and with RB wall-columns. The RB is a shear wall structure designed to accommodate specified seismic loads with its walls. Frame members such as beams or columns are designed to accommodate deformations of the walls in case of earthquake conditions.

The general building arrangement including watertight doors and sills for doorways where needed for flood control is presented in Figures 2.15.10.a through 2.15.10.o.

Seismic Category I Structure

The RB is a Seismic Category I structure designed to provide missile and tornado protection. Major nominal dimensions are as follows:

Structures	Dimensions (m)
Outer Box Walls:	
Overall height above top of basemat	57.9
Overall planar dimensions (outside)	
0-180 deg. direction	59.0
90-270 deg.direction	56.0
Wall thickness of each outer wall along 0-180 deg.	
Eighth level	0.3
Seventh level	0.3
Sixth level	0.5
Fifth level	0.8
Fourth level	0.9
Third level	1.2
Second level	1.3
First level	1.5

Structures	Dimensions (m)
Wall thickness of each outer wall along 90-270 deg.	
Eighth level	0.3
Seventh level betw. col. lines R2 and R6	0.6
Seven·· level betw. col. lines R1 and R2	
Seventh level betw. col. lines R6 and R7	0.3
Sixth level	0.9
Fifth level along col. line RA	1.2
Fifth level along col. line RG	0.9
Fourth level	1.2
Third level	1.2
Second level	1.3
First level	1.5
Containment:	
Diameter (I.D.)	29.0
Thickness	2.0
Height from top of basemat to the bottom of containment top slab	29.5
Pedestal:	
Diameter (I.D)	10.6
Thickness	1.7
Basemat thickness	5.5

Column sizes and floor slab thickness are provided in the general building arrangement figures. With major dimensions defined as listed above for specified reinforced concrete materials and design procedures, the dynamic characteristic of the RB structure is defined. Seismic adequacy of the detailed site-specific Reactor Building design will be evaluated using the dimensional characteristic noted above and approved analytical procedures and methodology for dynamic analysis of structures. This work will be in compliance with the required applicable ACI and AISC codes governing design of the reinforced concrete structures for nuclear power plants. Detailed analyses of the site-specific RB design will utilize appropriate site data for seismic events, floods, tornados, winds and other loading conditions.

The RB is arranged and designed to provide a structure with the following characteristics:

(1) Withstand applied loads - seismic, dead, live, dynamic, LOCA, etc.

(2) Physical protection and separation of systems, both mechanical and electrical.

(3) Radiation shielding.

(4) Clean and controlled access for personnel and equipments.

(5) Primary and secondary containment barriers.

The above characteristics are primarily accomplished by strategic grouping of equipment and positioning of building walls and floors.

The RB is arranged to achieve these characteristics as follows:

(1) Three Divisional Separation Arrangement - Separation is achieved by grouping each division of safety equipment, piping and electrical into separate quadrants of the RB. Each quadrant is in turn separated by the building structural walls.

(2) Counter measures for radiation - Radioactive equipment within the RB is positioned behind shield walls for personnel protection. The basic building layout contributes to minimized exposure since radioactive piping chases are routed vertically within the building next to the cylindrical containment wall. The equipment rooms containing radioactive process equipment are accessed from hallways near the building outer walls. Thus personnel entering radiation zones for equipment inspections or maintenance move from a low radiation area to progressive higher radiation areas.

(3) Clean and controlled access - The overall RB is partitioned into a clean zone and potentially contaminate zone with continuous walls separating the two major zones. Normal personnel access to the clean zones or contaminated zones of the building is accomplished by separate entrances to the building. Contaminated equipment is moved only in contaminated spaces for removal from the building.

Flooding Protection

To protect against external flood damage, the following design features are provided:

(1) wall thickness below flood level greater than 0.6m.

(2) water stops provided in all construction joints below grade.

(3) watertight doors and piping penetrations installed in external walls below flood level.

(4) waterproof coating on exterior walls below grade.

(5) foundations and walls of structures below grade are designed with water stops at expansion and construction joints.

(6) roofs are designed to prevent pooling of water.

(7) building will be sited so that the design basis maximum flood level is one foot (0.[illegible]m) below grade.

To protect against internal flood damage, the following design features are provided:

(1) flooding in one division is limited to that division and flood water is prevented to propagate to other divisions by elevation differences and divisional separation, also by watertight doors or sealed hatches.

(2) sloped floor and curbs to divert water to floor drains and sumps.

(3) sills for doorways to provide flood control.

(4) watertight doors installed below internal flood level.

(5) wall thickness below internal flood level greater than 0.6m.

(6) service water system does not enter reactor building.

The flood protection measures also guard against flooding from the on-site storage tanks that may rupture. There will be no direct entries to the RB. All plant entries start 0.3m above grade. Any flash flooding that may result from tank rupture will drain away from the site and cause no damage to site equipment. There is no service water pipe line routing through the RB. All cooling loops have a finite volume of water.

Additional specific provisions for flood protection include administrative procedures to assure that all watertight doors and hatch covers are locked in the event of flood warning. If local seepage occurs through the walls, it is controlled by sumps and sump pumps from perimeter hallway at basement level. On the basement level all essential safety equipment is located off perimeter hallways by a second divisional barrier with watertight doors.

Compartment flooding from postulated component failures are evaluated. Floor-by-floor analysis of potential pipe failure generated flooding events in the reactor building shows the following:

(1) Where extensive flooding may occur in a division rated compartment, propagation to other divisions is prevented by watertight doors or sealed hatches. Flooding in one division is limited to that division and perimeter hallways. Flood water is prevented from entering other divisions by walls and watertight doors.

(2) Leakage of water from large circulating water lines, such as reactor building cooling water lines may flood individual rooms and corridors, but through sump alarms and leakage detection systems the control room is alerted and can control flooding by system isolation. Divisional areas are protected by watertight doors, or where only limited water depth can occur, by raised sills with pedestal mounted equipment within the protected rooms.

(3) Limited flooding that may occur from manual firefighting or from lines and tanks having limited inventory is restrained from entering division areas by raised sills and elevation differences.

Therefore, within the reactor building, internal flooding events as postulated will not prevent the safe shutdown of the reactor.

Fire Protection

The basic layout of the plant and the choice of system is such as to enhance the tolerance of the ABWR plant to fire. The systems are designed such that there are three independent safety-related divisions, any one of which is capable of providing safe shutdown of the reactor. In addition, there are non-safety-related system such as the condensate and feedwater systems which can be used to achieve safe shutdown. The plant arrangement is such that points of possible common cause failure between these non-safety-related systems and the safety-related systems have been minimized.

The design objective has been to assure that independence of the redundant systems required or available for safe shutdown is not compromised by fire, the consequences of fire or the failure of fire protection equipment or systems. This design priority was met by implementing a coordinated overall design including fire considerations for the following plant features:

Plant arrangement — The plant is laid out with the control building located between the reactor and turbine buildings so that power and control signals from the reactor and turbine buildings enter the control building on opposite sides of the control building. The buildings are laid out internally so that fire areas of like divisions are grouped together in block form as much as possible. This grouping is coordinated from building to building so that the divisional fire areas line up adjacent to each other at the interface between the reactor and control building. An arrangement of this fashion naturally groups piping, HVAC ducts and cable trays together in divisional arrangements and does not require routing of services of one division across space allotted to another division.

Divisional separation — As stated above, there are three complete divisions of safety-related cooling systems. Any one division is capable of safe or emergency shutdown of the plant so that an outage of one division for maintenance, a single random failure occur and the remaining functional division would still be able to provide safe plant shutdown. In general, systems are grouped together by safety division so that, with the exceptions of the primary containment, the control room and the remote shutdown room (when operating from the remote shutdown panels) there is only one division of safe shutdown equipment in a fire area. Complete burnout of any fire area without recovery will not prevent safe shutdown of the plant, therefore, complete burnout of a fire area is acceptable. All divisions are present in the control room. It is the purpose of the remote shutdown panel to provide redundant control of the safe shutdown function from outside of the control room. The controls on the remote shutdown panel are hard wired to the field devices and power supplies. The signals between the remote shutdown panel and control room are multiplexed over fiber optic cables so that there are no power interactions between the control room and the remote shutdown panel. During normal plant operation the remote shutdown room is divided into two rooms by a closed sliding fire door. A fire in one divisional section will not affect the other divisional section.

Fire containment system — The fire containment system is the structural system and appurtenances that serve together to confine the direct effects of a fire to the fire area in which the fire originates. The fire containment system is required to contain a fire with a maximum severity by the time-temperature curve defined in ASTM E119 for a fire with a duration of three hours.

Combustible loading — Allowable combustible loadings for the plant were established.

HVAC systems — The HVAC systems have been matched to the divisional areas which they serve. The divisions are in separate fire areas and each fire area is served by its corresponding division of HVAC.

Smoke control system — Major features are provided for the smoke control system for the plant, such as venting of fire areas, pressure control across the fire barriers, pressure control and purge air supply, augmented and directed clean air supply, smoke control by fans and systems external to the fire area, and removal of smoke and heat from the fire by fans.

Spurious control actions — The systems are separated by fire areas on a divisional basis as stated above. In addition, the multiplexed design is such that in case of fire in the control room, spurious control signals will not be sent out from the control room.

Support systems — Support systems such as HVAC and reactor building closed cooling water systems are designed as a safety- related if they support safety-related systems. They are given divisional assignments and separated by fire barriers in the same fashion as the safety-related primary systems

Fire alarm system — Fire alarm systems are designated as safety-related. It is a requirement that fire alarm systems be zoned by division according to the divisional assignment of the area which each zone covers.

Fire suppression system — Automatically initiated fire suppression systems are initiated on a divisional basis so that there are no inter-actions between divisions.

Personnel access routes — The personnel access routes for fire suppression activities have been reviewed to see that access compatible with the design of the fire barriers, HVAC and smoke control systems has been provided. A source of clean cool air is provided for access routes to fire areas. The air supply is by fans out of the fire area experiencing the fire.

Manual fire suppression activities — The plant is designed such that the divisional area in which a fire is occurring will be apparent to the operators at the time the fire is discovered. If the fire is significant, the operator can transfer operations to one of the two unaffected divisions and shutdown the equipment in the affected division.

The intent of providing features described above is to have an adequate balance in:

(1) preventing fires from starting;

(2) timely detection and extinguishing fires that occur, thus limiting fire damage; and

(3) designing safety-related systems so that a fire that starts in spite of the fire prevention program and burns out of control for a considerable length of time will not prevent safe shutdown.

In addition, fire protection systems are designed so that their inadvertent operation or the occurrence of a single failure in any of these systems will not prevent plant safe shutdown.

It is required that the ABWR design shall provide 3-hour fire rated penetration seals for all high energy piping or, as a minimum, state those conditions when such seals cannot be provided and what will be installed as a substitute.

Pipe Breaks Protection

Structures, component arrangement, pipe runs, pipe whip restraints and compartmentalization are designed to protect against dynamic effects associated with a pipe break event. Pipe whip restraints preclude damage base on the pipe break evaluation. Protection against pipe break event dynamic effects is provided to fulfill the following objectives:

(1) Assure that the reactor can be shut down safely and maintained in a safe cold shutdown condition and that the consequences of the postulated piping failure are mitigated to acceptable limits without offsite power.

(2) Assure that containment integrity is maintained.

(3) Assure that the radiological doses of a postulated piping failure remain below the limits of 10 CFR 100.

To comply with the above objectives, the essential systems, components and equipment are identified. An analysis of pipe break events is performed to identify those essential systems, components and equipment that provide protective actions required to mitigate, to acceptable limits, the consequences of the pipe break event. By means of the design features such as separation, barriers, and pipe whip restraints, adequate protection is provided against the effects of pipe break events for essential items to an extent that their ability to shut down the plant safely or mitigate the consequences of the postulated pipe failure would not be impaired.

Tornado and Missile Protection

The Reactor Building is not a vented structure. The exposed exterior roofs and walls of the RB are designed for the required pressure drop. Tornado dampers are provided on all air intake and exhaust openings. These dampers are designed to withstand the specified negative pressure of 1.46 psi.

Missiles considered in the RB design are those that could result from a plant-related failure or incident including failures within and outside of containment, and environmentally-generated missiles. The structures, shields, and barriers that have been designed to withstand missile effects, the possible missile loadings, and the procedures to which each barrier has been designed to resist missile impact are described and analyzed in detail in the process of design.

Tornado-generated missiles have been determined to be the limiting natural phenomena hazard in the design of all structures required for safe shutdown of the nuclear power plant. Since tornado missiles are used in the design, it is not necessary to consider other externally generated missiles. The essential safety equipment in the reactor building is located below grade level except for the divisional diesel generator units. Thus, it is unnecessary to consider external missiles for most safety equipments. The divisional diesel generators and supporting equipment are located at grade level and protected by tornado resistant walls. The primary containment is embedded within the RB and protected by multiple walls and floors from external missiles.

Internally generated missiles (outside containment) are considered to be those resulting internally from plant equipment failures within the ABWR Standard Plant but outside containment. Examples of potential rotating equipment missiles are RCIC steam turbine. Examples of potential pressurized components missiles are valve bonnets, valve stems and retaining bolts. After a potential missile has been identified, its statistical significance is determined by an approved procedure. A statistically significant missile is defined as a missile which could cause unacceptable plant consequences or violation of the guidelines of 10 CFR 100. Barriers are designed based on the approved procedures to protect against the potential missiles.

Protection of essential structures, systems and components is afforded by one or more of the following practices:

(1) Location of the system or component in an individual missile-proof structure;

(2) Physical separation of redundant systems or components of the system for the missile trajectory path or calculated range;

(3) Provision of localized protection shields or barriers for systems or components;

(4) Design of the particular structure or component to withstand the impact of the most damaging missile;

(5) Provision of the design features on the potential missile source to prevent missile generation; and/or

(6) Orientation of the potential missile source to prevent unacceptable consequences due to missile generation.

Radioactive Shielding and Containment

Administrative programs and procedures, in conjunction with facility design, ensure that the occupational radiation exposure to personnel will be kept as low as reasonably achievable (ALARA). The primary objective of the radiation shielding for RB design is to protect operating personnel and the general public from radiation emanating from the reactor, the power conversion systems, the radwaste process systems, and the auxiliary systems, while maintaining appropriate access for operation and maintenance. The radiation shielding is also designed to keep radiation doses to equipment below levels at which disabling radiation damage occurs. For further discussion see Section 3.7, Radiation Protection.

The secondary containment boundary completely surrounds the primary containment vessel (PCV) except for the basemat and, together with clean zone, comprises the reactor building. The secondary containment encloses all penetrations, except those into the steam tunnel, through the primary containment that may become a potential source of radioactive release after an accident. During normal plant operation, the secondary containment areas are kept at a negative pressure with respect to the environment and clean zone by the HVAC system. Following an accident, the standby gas treatment system (SGTS) provides this function.

Fission products that may leak from the primary to the secondary are processed by the SGTS before being discharged to the environment. The HVAC exhaust systems and SGTS are located within the secondary containment to assure collection of any leakage. The secondary containment provides detection of the level of radioactivity released to the environment during abnormal and accident plant conditions. Personnel or material entrances to the secondary containment consist of vestibules with interlocked doors.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.15.10 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the Reactor Building.

Table 2.15.10: Reactor Building

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Reactor Building general arrangement is shown in Figures 2.15.10.a through 2.15.10.o.	1. Plant walk through.	1. The configuration conforms with Figures 2.15.10.a through 2.15.10.o.
2. Design features are provided to protect against design basis internal and external floods.	2. Review construction records and perform visual inspections of the flood control features.	2. For external flooding: a. Exterior wall thickness below flood level greater than o.6m. b. Water stops. c. Watertight doors and piping penetrations below flood level. d. Water proof coating on exterior walls. e. Foundations and walls of structures below grade are designed with water stops at expansion and construction joints. f. Roofs are designed to facilitate drainage and prevent pooling. g. Building will be sited so that the design basis maximum flood level is one foot(0.3m) below grade. For internal flooding: a. Flooding in one division is limited to that division by preventing flood water from propagating to other divisions by elevation differences and divisional separation, also by watertight doors or sealed hatches. b. Sloped floors and curbs to divert water to floor drains and sumps. c. Sills for doorways as required to provide flood control. d. Watertight doors installed below internal flood level. e. Wall thickness below interal flood level greater than 0.6m. f. Service water system does not enter reactor building.

Table 2.15.10: Reactor Building (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3. The RB is a Seismic Category I structure and has major dimensions defined in the certified design.	3. Plant walk through to check and verify RB major dimensions including column sizes and floor slab thickness. Review final design record for material properties, site input data and analytical procedures and methodology for seismic analysis. Visual inspections of structures and review of as-built documentation will be conducted to assure compliance with the certified design commitments.	3. Structures have dimensions compatible with data in the certified design. (Figures 2.15.10.a through 2.15.10.o).
4. The detail structural design will be based on required applicable ACI and AISC codes and will use site data for seismic events, floods, tornados,winds and other loading conditions.	4. The Reactor Building design documentation will be reviewed.	4. Confirmation that the as-built design is in compliance with required applicable ACI and AISC requirements and is based on appropriate site design data.
5. The RB is designed to have adequate radiation shielding to ensure that the occupational radiation exposure to personnel will be kept as low as reasonably achieveable (ALARA).	5. Perform dimensional inspections of the RB walls, ceiling,floors, and other structural features.	5. See Section 3.7, Radiation Protection.
6. The RB is designed to protect against design basis tornado and tornado generated missiles.	6. Review construction records and perform visual inspections of the tornado protection features.	6. a. Per Figures 2.15.10.a through 2.15.10.o. for RB wall and roof dimensions. b. HVAC dampers designed for differential pressure > 1.46 psi. c. HVAC dampers and tornado missile barriers are provided.
7. The RB provides walls and other facilities for separation required by the three independent divisional safe shutdown systems.	7. Review of construction records and visual examinations of the as built facility.	7. Confirmation that separation of the redundant systems for safe shutdown is provided.

Table 2.15.10: Reactor Building (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8. Protection against pipe break event dynamic effects is provided to assure that the reactor can be shut down safely, that the containment integrity is maintained, and that the radiological doses of a postulated piping failure remain below the limits.	8. Review the design documentation to assure that the analysis of pipe break events is performed for design features such as separations,barriers, and pipe whip restraints provided for essential items for plant safe shutdown.	8.Comformation that the as built structures are in compliance with the design documentation. For radiation protection, see Section 3.7, Radiation Protection.
9. Secondary containment boundary copletely surrounds the PCV and encloses all PCV's penetrations that may become a potential source of radioactive release after an accident.	9. Review RB construction records and perform visual inspections of the as-built arrangement. Reference to Sec.2.14.4 for SGTS and Sec.2.15.5 for HVAC functions.	9. a. Per Figures 2.15.10.a through 2.15.10.o. b. Sec.2.14.4, SGTS. c. Sec.2.15.5, HVAC.

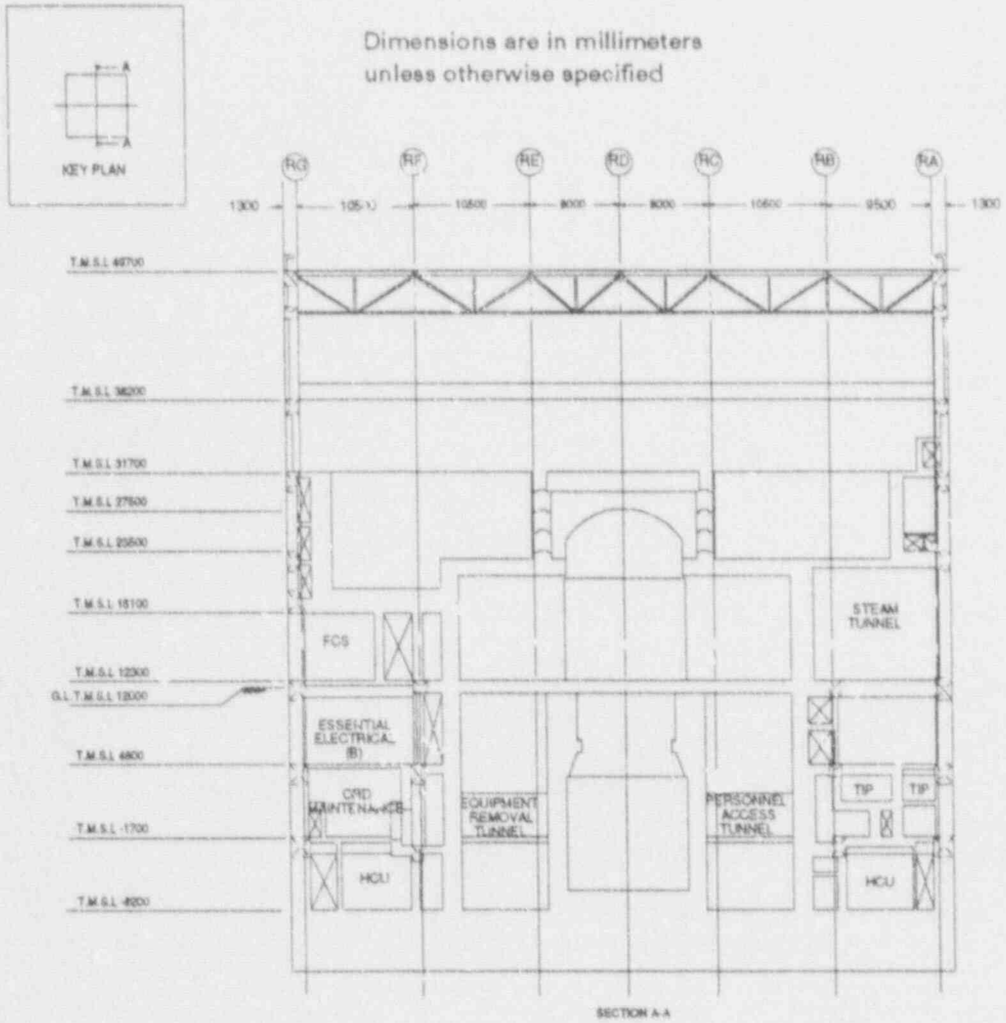


Figure 2.15.10a Reactor Building Arrangement — 0°/180°

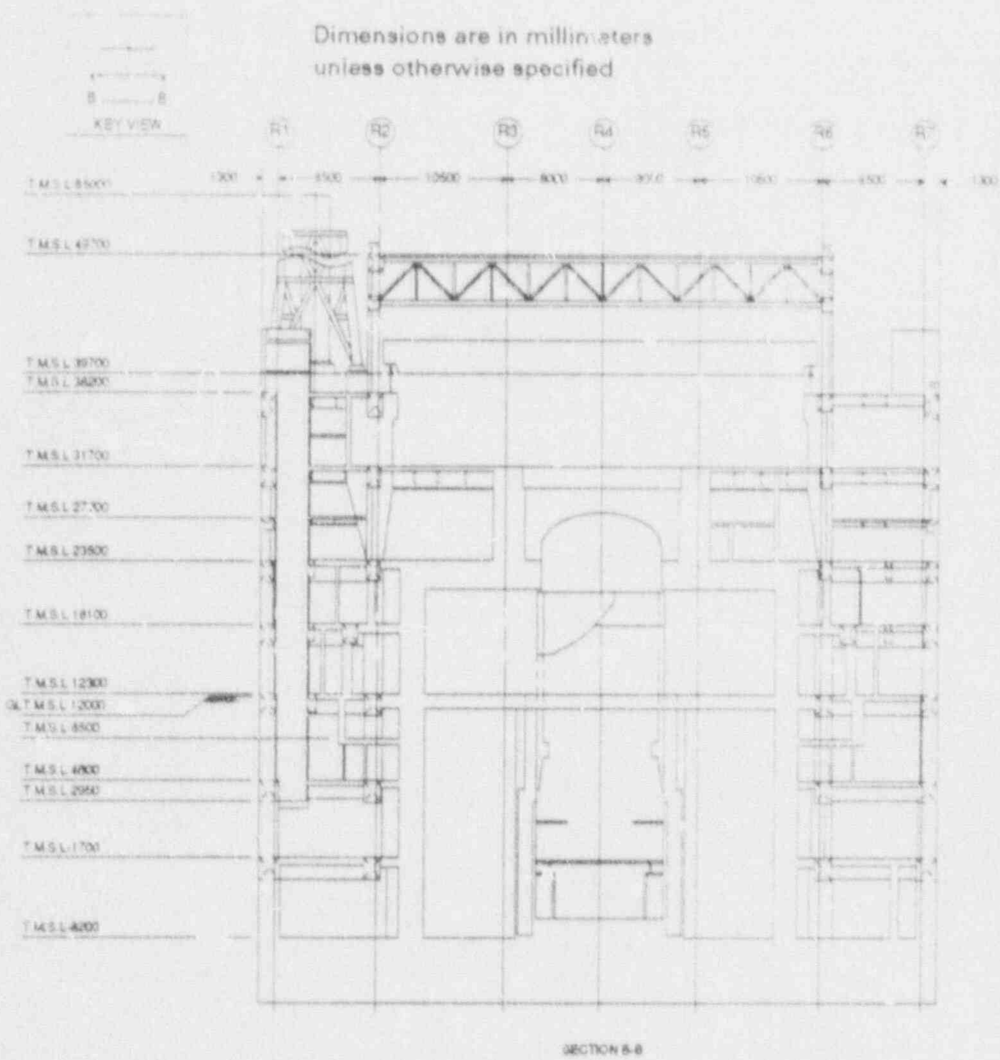
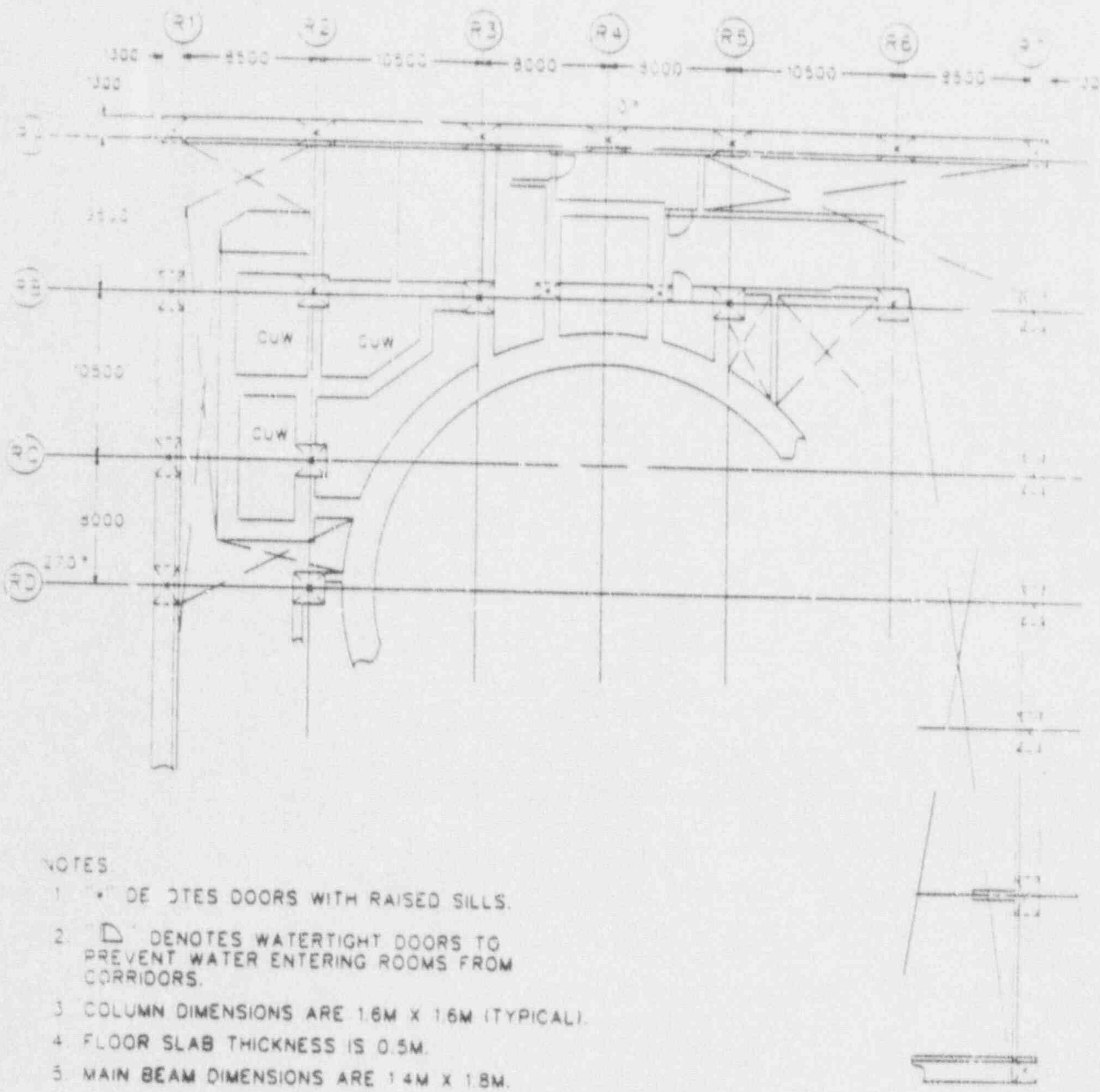


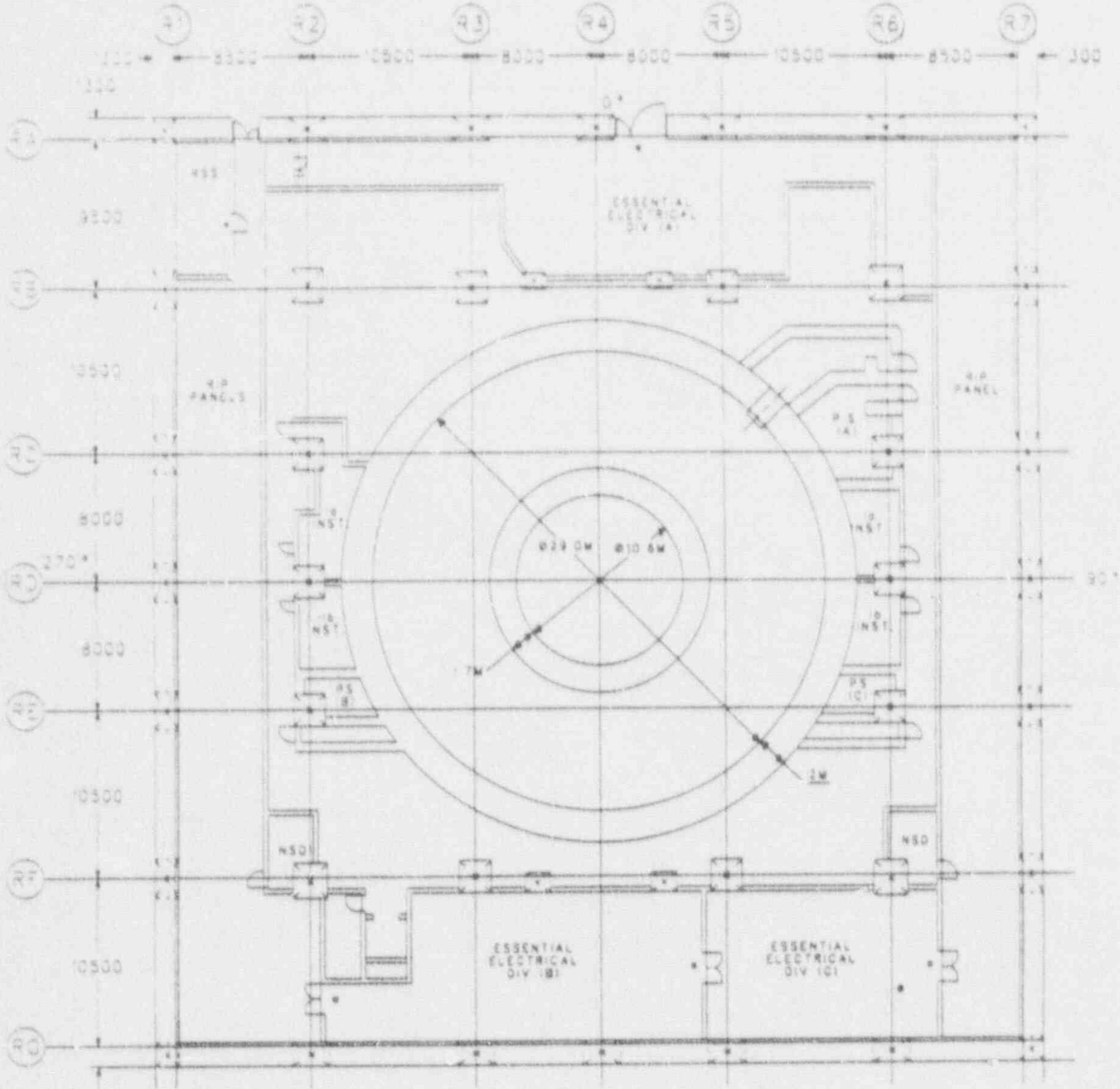
Figure 2.15.10b Reactor Building Arrangement — 270°/90°



NOTES

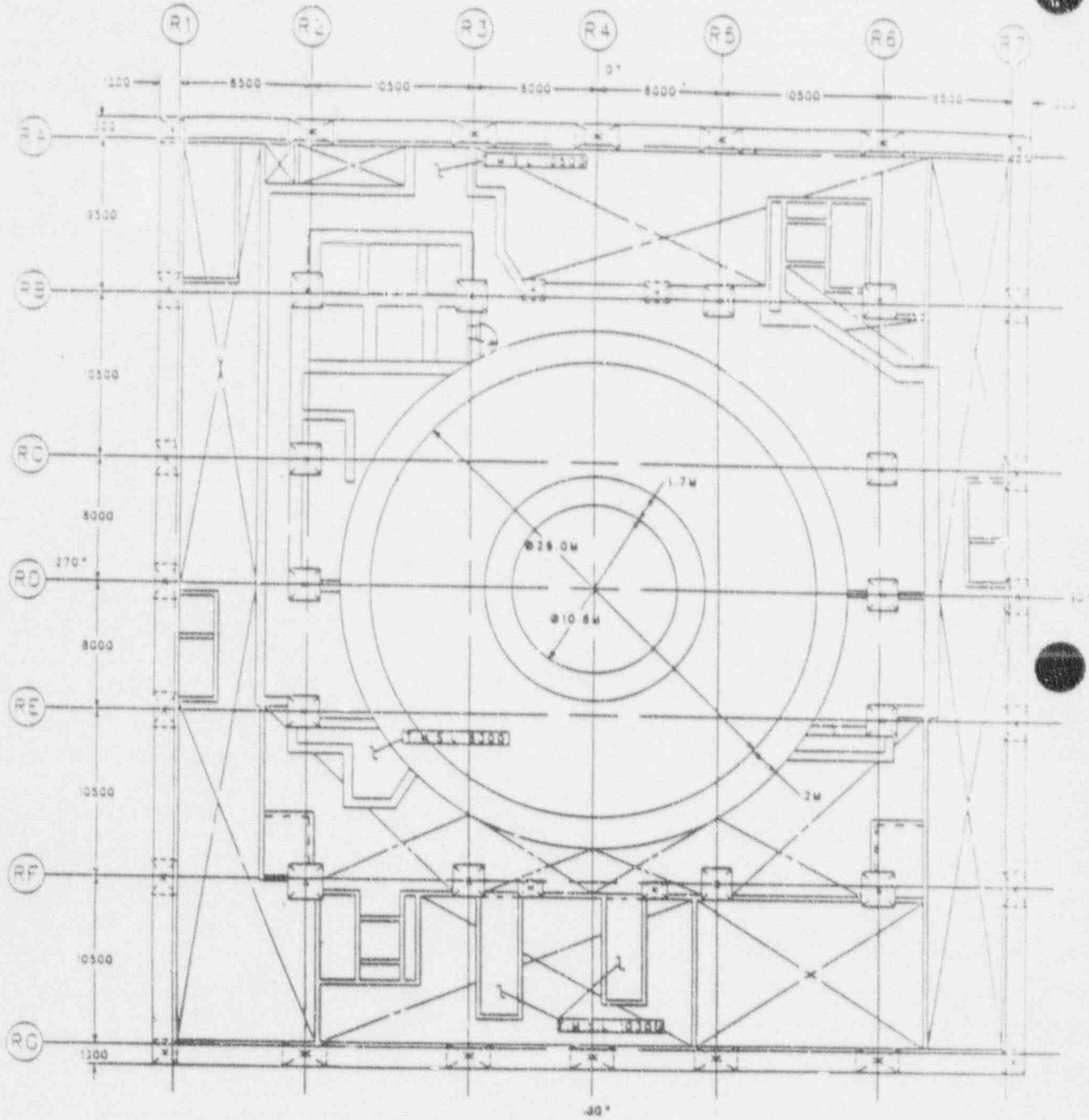
1. "•" DE OTES DOORS WITH RAISED SILLS.
2. "◻" DENOTES WATERTIGHT DOORS TO PREVENT WATER ENTERING ROOMS FROM CORRIDORS.
3. COLUMN DIMENSIONS ARE 1.6M X 1.6M (TYPICAL).
4. FLOOR SLAB THICKNESS IS 0.5M.
5. MAIN BEAM DIMENSIONS ARE 1.4M X 1.8M.

Figure 2.15.10f Reactor Building Arrangement—Elevation 1500 mm



NOTES:
1. •" DENOTES DOORS WITH RAISED SILLS.
2. "⊐" DENOTES WATERTIGHT DOORS TO PREVENT WATER ENTERING ROOMS FROM CORRIDORS.
3. COLUMN DIMENSIONS ARE 1.8M X 1.8M (TYPICAL).
4. FLOOR SLAB THICKNESS IS 0.6M.
5. MAIN BEAM DIMENSIONS ARE 1.5M X 1.8M.

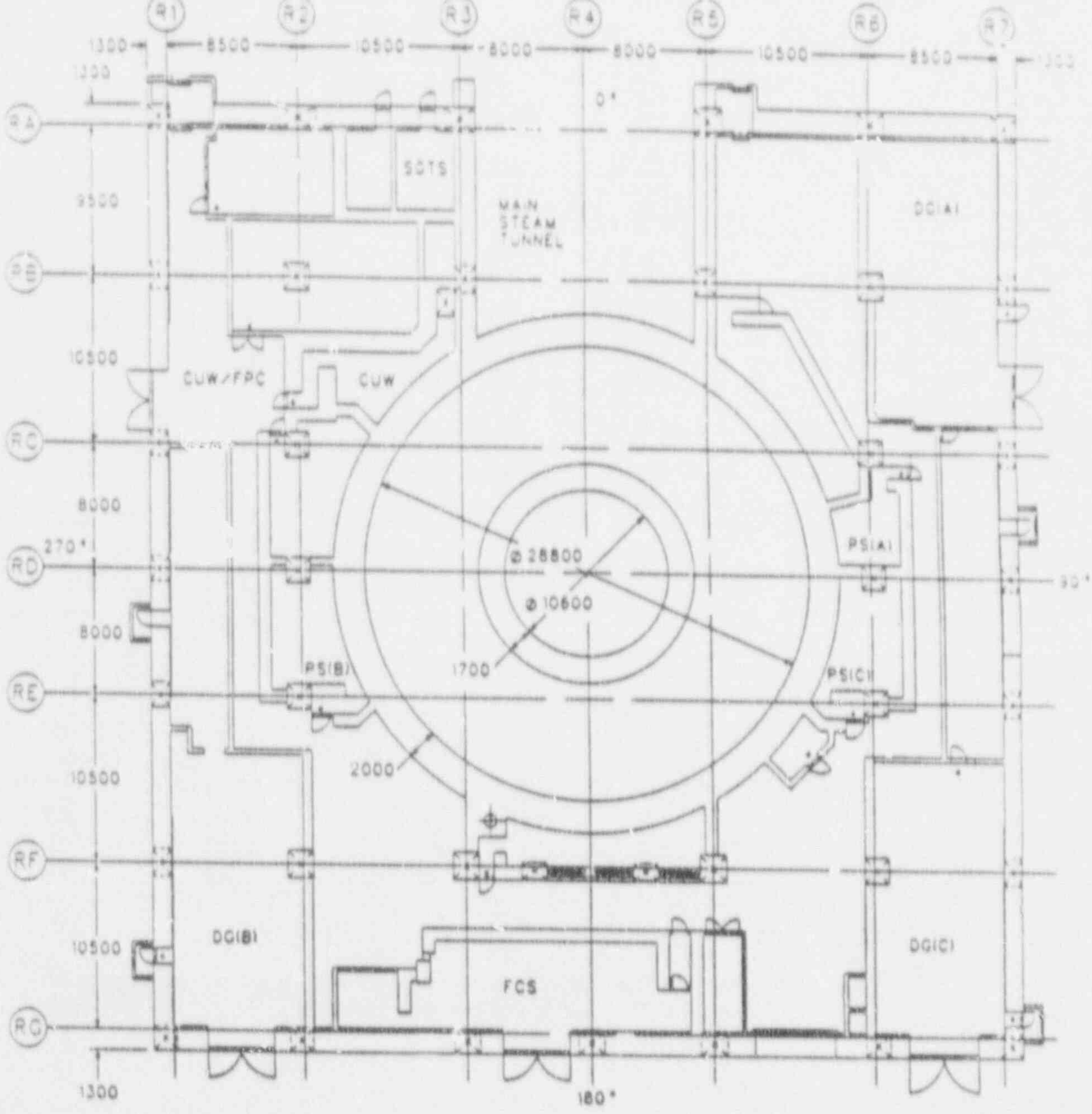
Figure 2.15.10g Reactor Building Arrangement—Elevation 4800 mm



NOTES:

1. "◺" DENOTES WATERTIGHT DOORS TO PREVENT WATER ENTERING ROOMS FROM CORRIDORS.
2. COLUMN DIMENSIONS ARE 1.8M X 1.8M (TYPICAL).
3. MAIN BEAM DIMENSIONS ARE 1.5M X 1.8M.

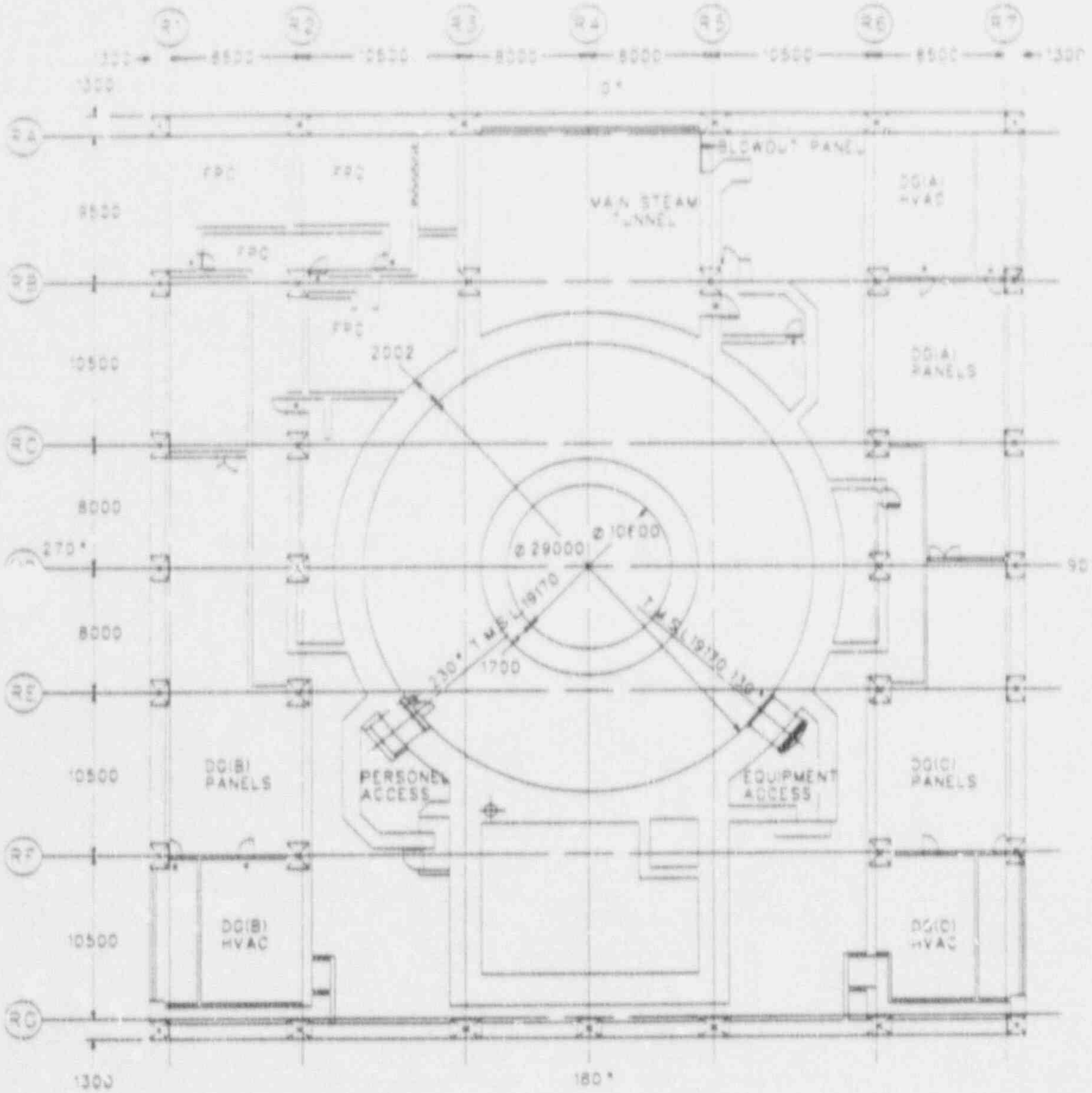
Figure 2.15.10h Reactor Building Arrangement—Elevation 8500 mm



NOTES:

1. "×" DENOTES DOORS WITH RAISED SILLS.
2. "⌂" DENOTES WATERTIGHT DOORS TO PREVENT WATER ENTERING ROOMS FROM CORRIDORS.
3. COLUMN DIMENSIONS ARE 1.6M X 1.6M (TYPICAL).
4. FLOOR SLAB THICKNESS IS 0.5M.
5. MAIN BEAM DIMENSIONS ARE 1.4M X 1.8M.

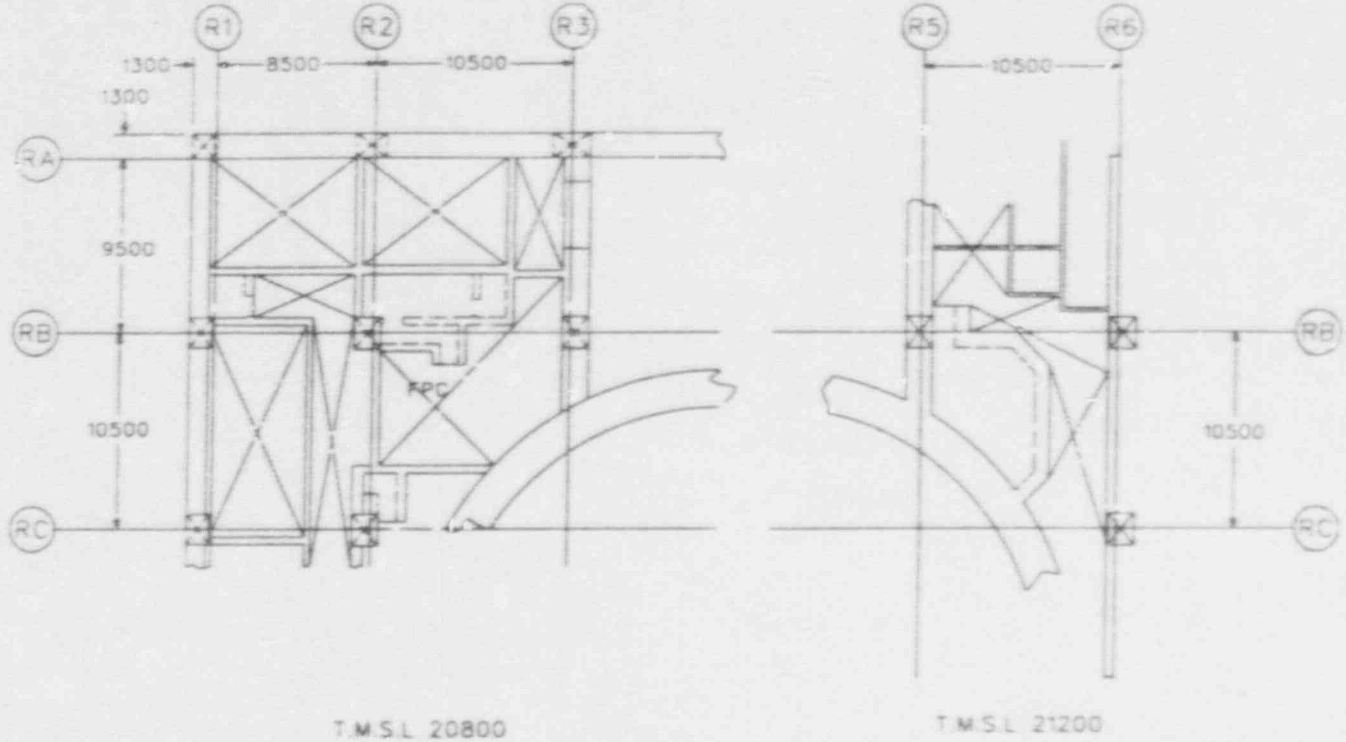
Figure 2.15.10i Reactor Building Arrangement—Elevation 12300 mm



NOTES:

1. "•" DENOTES DOORS WITH RAISED SILLS.
2. "◻" DENOTES WATERTIGHT DOORS TO PREVENT WATER ENTERING ROOMS FROM CORRIDORS.
3. COLUMN DIMENSIONS ARE 1.6M X 1.6M (TYPICAL).
4. FLOOR SLAB THICKNESS IS 0.5M.
5. MAIN BEAM DIMENSIONS ARE 1.4M X 1.8M.

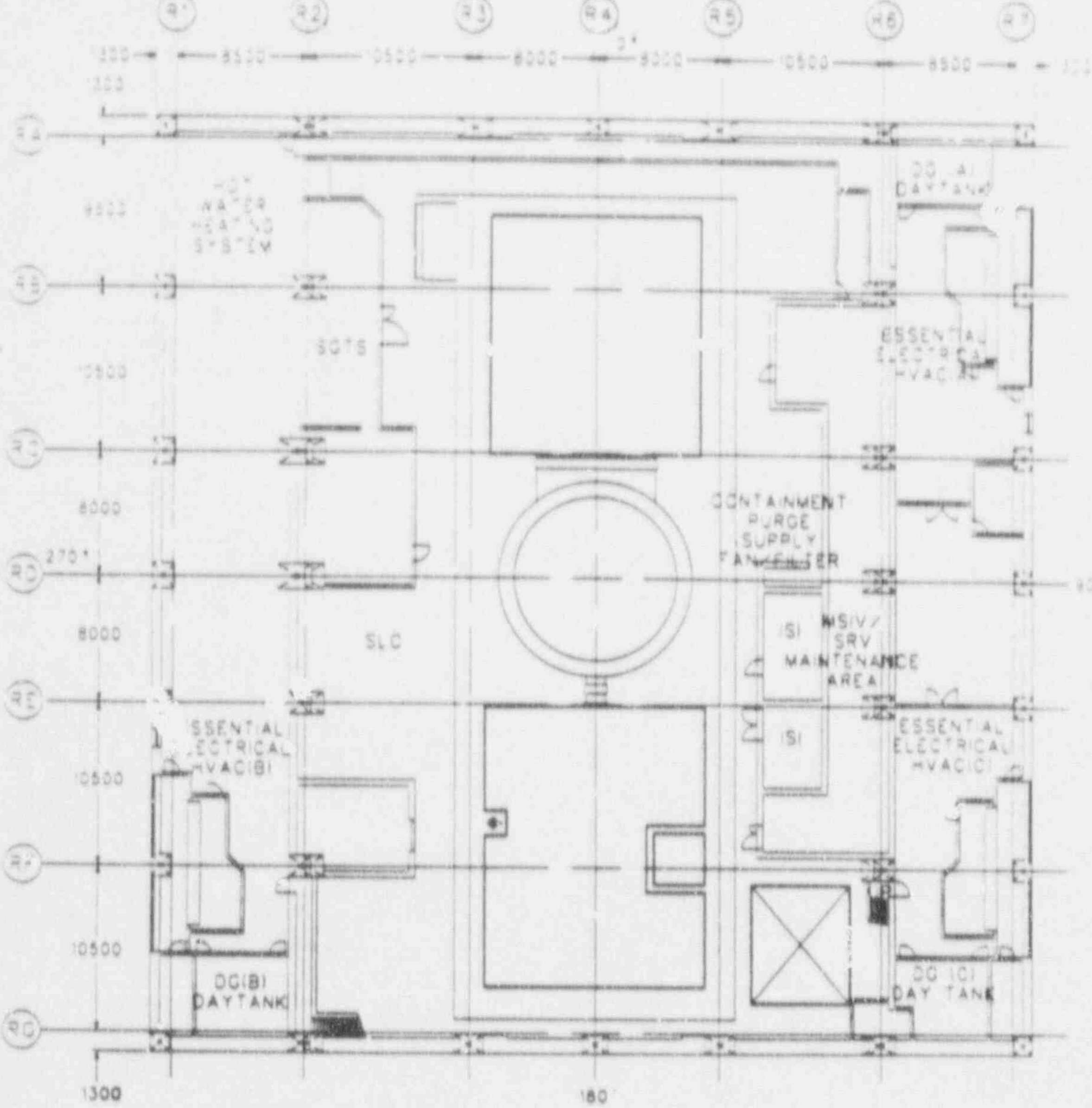
Figure 2.15.10j Reactor Building Arrangement—Elevation 18100 mm



NOTES:

1. "•" DENOTES DOORS WITH RAISED SILLS.
2. "D" DENOTES WATERTIGHT DOORS TO PREVENT WATER ENTERING ROOMS FROM CORRIDORS.
3. COLUMN DIMENSIONS ARE 1.4M X 1.4M (TYPICAL).
4. FLOOR SLAB THICKNESS IS 0.5M.
5. MAIN BEAM DIMENSIONS ARE 1.5M X 1.8M.

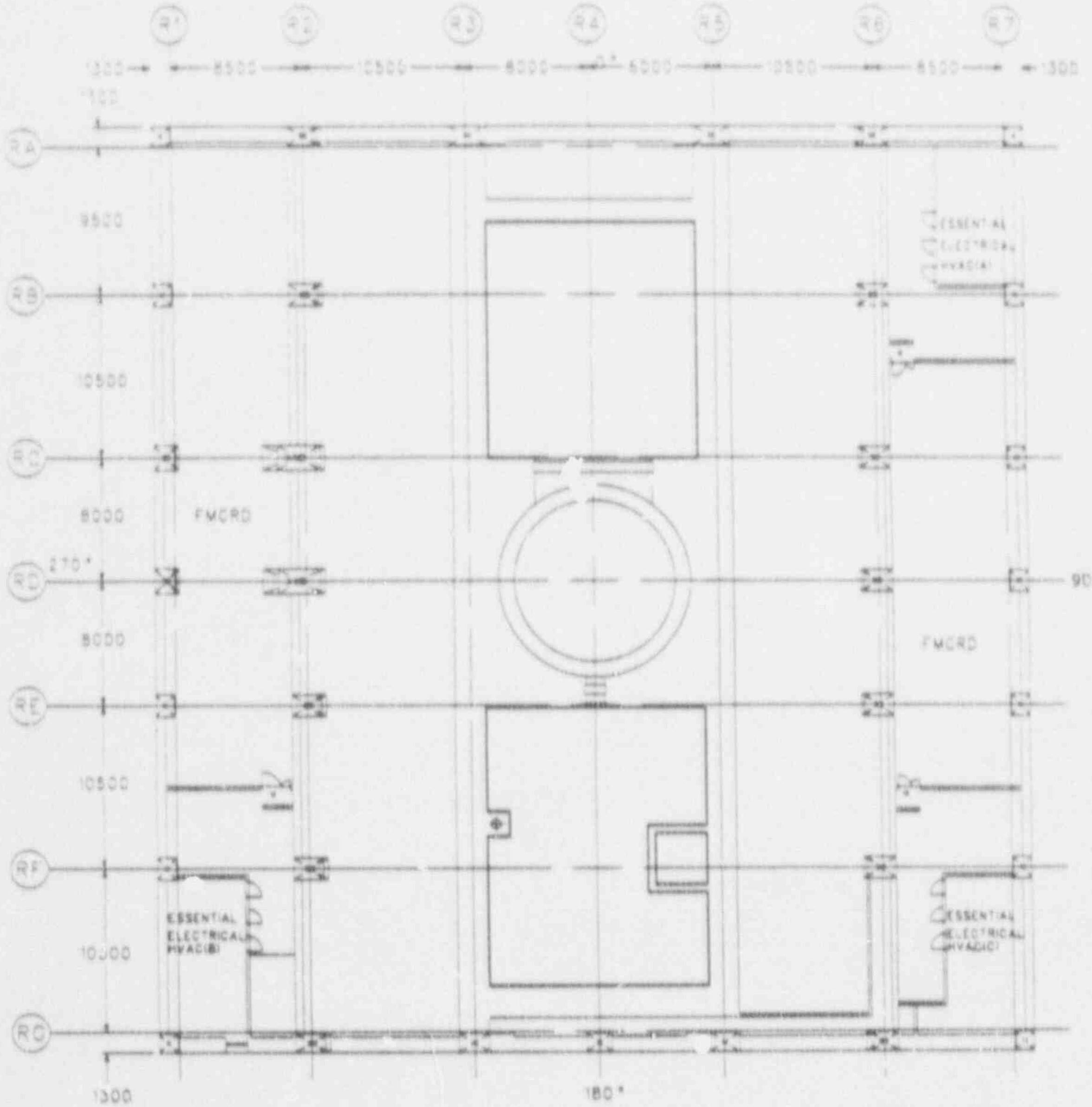
Figure 2.15.10k Reactor Building Arrangement—Elevation 20800 and 21200 mm



NOTES:

1. "*" DENOTES DOORS WITH RAISED SILLS.
2. "D" DENOTES WATERTIGHT DOORS TO PREVENT WATER ENTERING ROOMS FROM CORRIDORS.
3. COLUMN DIMENSIONS ARE 1.4~2.2 X 1.4M (TYPICAL)
4. FLOOR SLAB THICKNESS IS 0.5M.
5. MAIN BEAM DIMENSIONS ARE 1.2M X 1.8M.

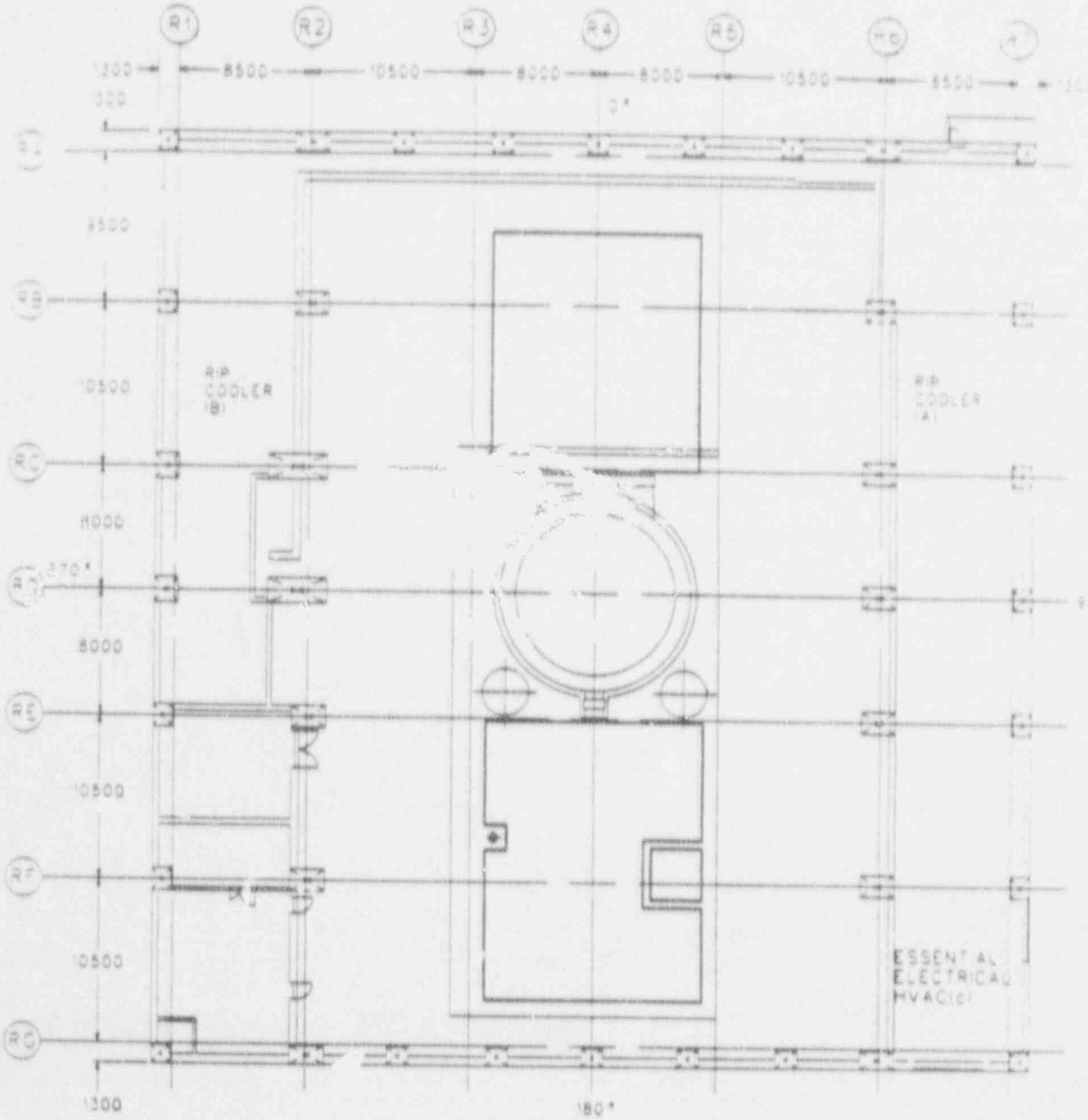
Figure 2.15.10l Reactor Building Arrangement—Elevation 23500 mm



NOTES:

1. "*" DENOTES DOORS WITH RAISED SILLS.
2. "◺" DENOTES WATERTIGHT DOORS TO PREVENT WATER ENTERING ROOMS FROM CORRIDORS.
3. COLUMN DIMENSIONS ARE 1.4~2.2 X 1.4M (TYPICAL)
4. FLOOR SLAB THICKNESS IS 0.5M.
5. MAIN BEAM DIMENSIONS ARE 1.2M X 1.8M.

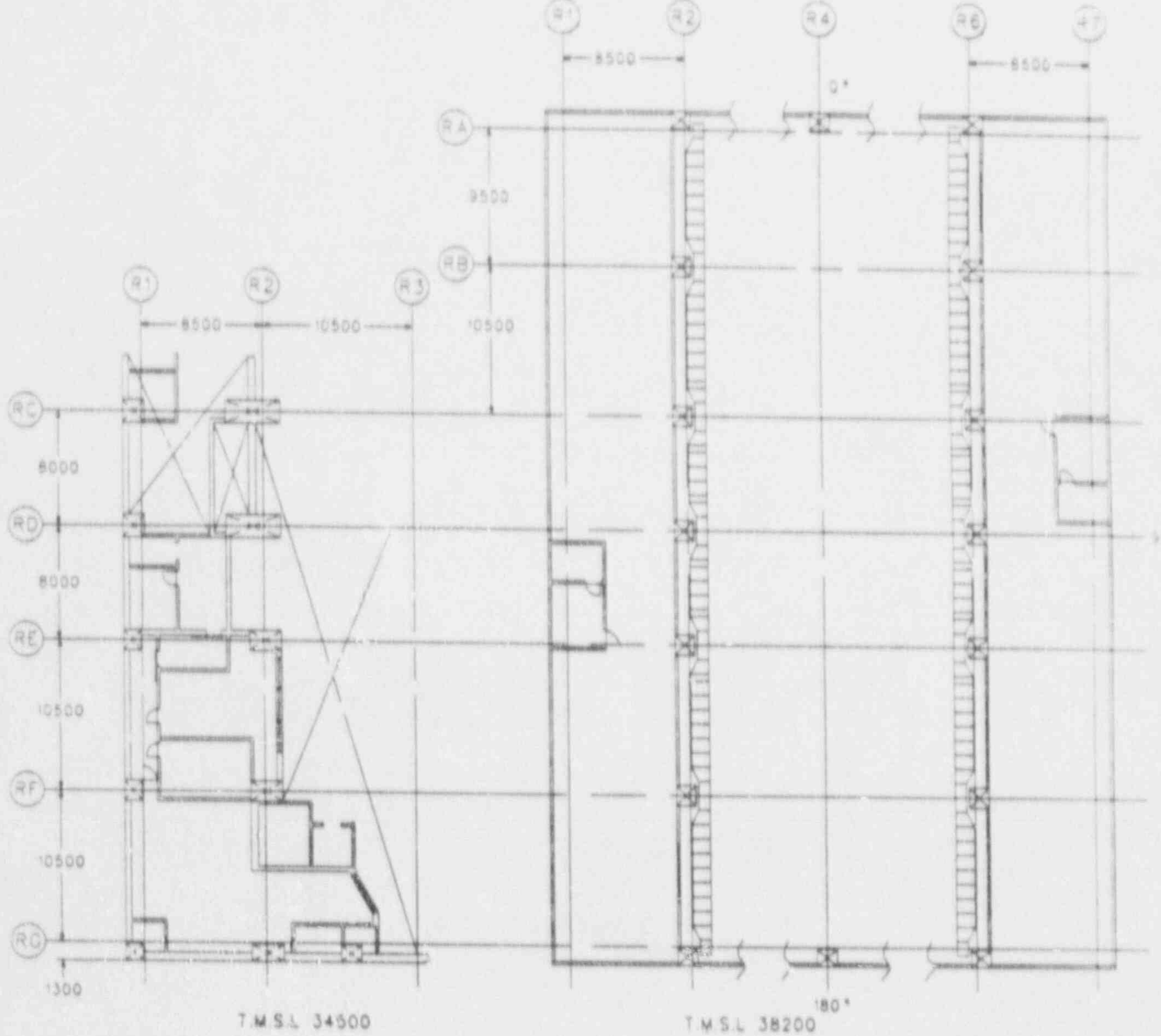
Figure 2.15.10m Reactor Building Arrangement—Elevation 27200 mm



NOTES:

1. "•" DENOTES DOORS WITH RAISED SILLS.
2. "D" DENOTES WATERTIGHT DOORS TO PREVENT WATER ENTERING ROOMS FROM CORRIDORS.
3. COLUMN DIMENSIONS ARE 2.2M X 1.6M (TYPICAL).
4. FLOOR SLAB THICKNESS IS 0.5M.
5. MAIN STEEL H-SECTION BEAM DIMENSIONS ARE BH-1.5 X 0.7M.

Figure 2.15.10n Reactor Building Arrangement—Elevation 31700 mm



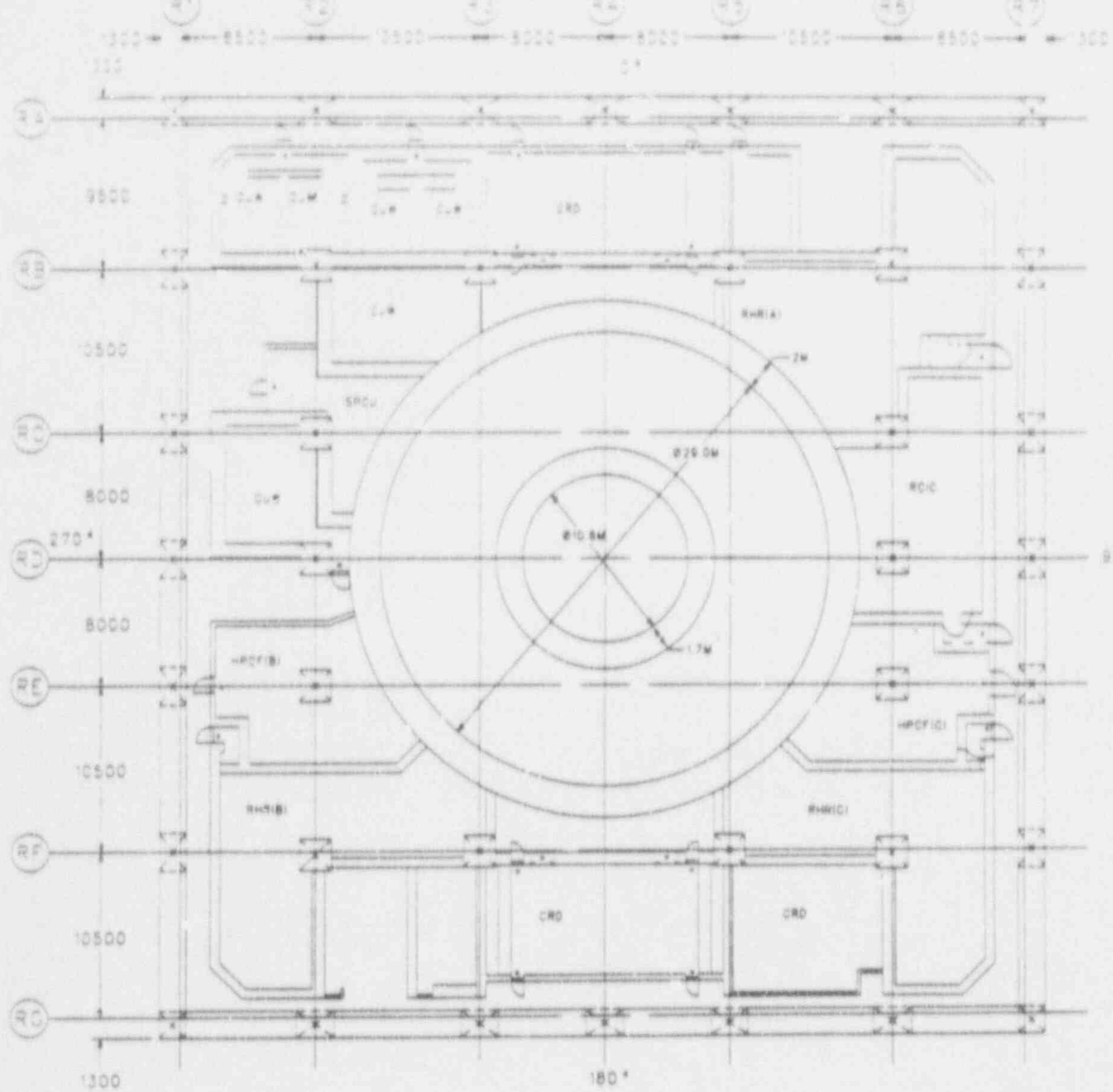
NOTES: (FOR T.M.S.L. 34500)

1. COLUMN DIMENSIONS ARE 2.2M X 1.4M.
2. FLOOR SLAB THICKNESS IS 0.5M.

NOTES: (FOR T.M.S.L. 38200)

1. COLUMN DIMENSIONS ARE 1.4M X 1.4M (TYPICAL)
2. ROOF THICKNESS IS 0.5M
3. MAIN BEAM DIMENSIONS ARE BH-0.8 X 0.45

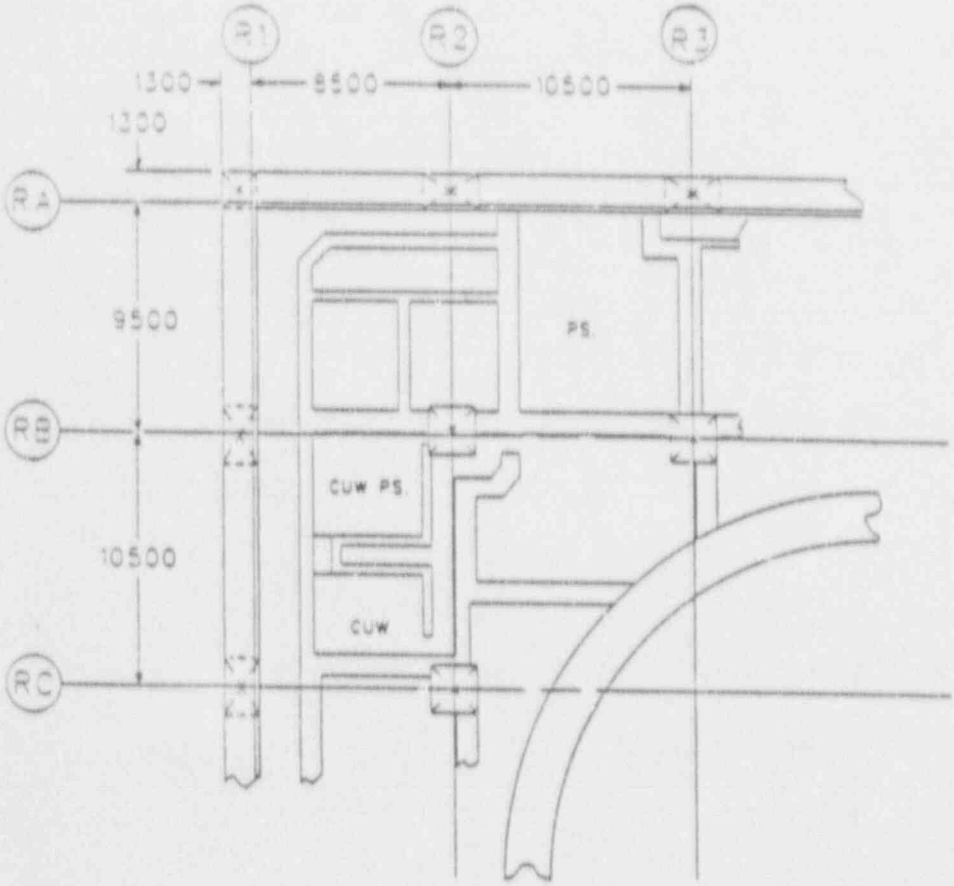
Figure 2.15.10o Reactor Building Arrangement—Elevation 34500 and 38200 mm



NOTES:

1. "•" DENOTES DOORS WITH RAISED SILLS.
2. "D" DENOTES WATERTIGHT DOORS TO PREVENT WATER ENTERING ROOMS FROM CORRIDORS.
3. COLUMN DIMENSIONS ARE 2.0M X 2.0M (TYPICAL).
4. BASEMENT THICKNESS IS 5.5M.

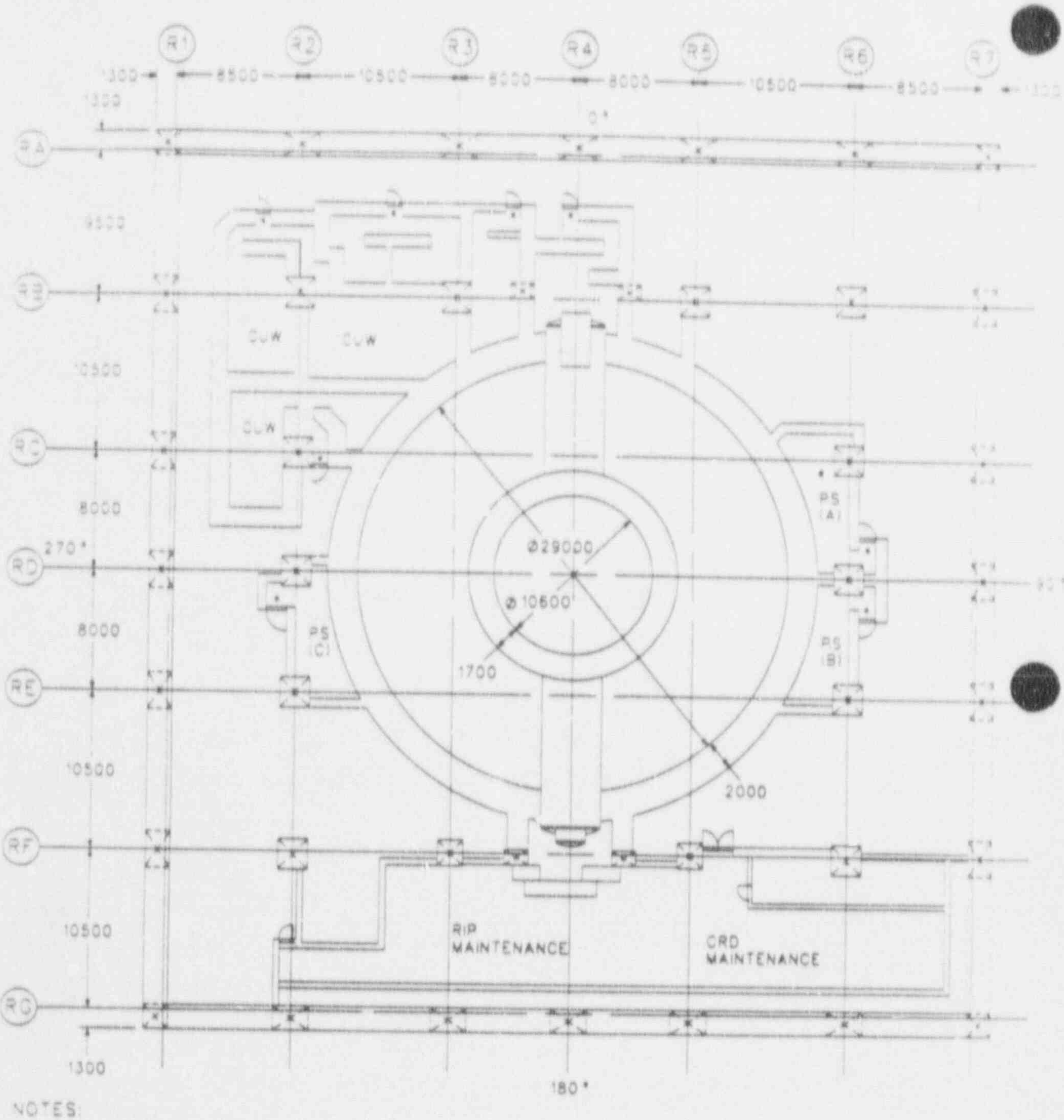
Figure 2.15.10c Reactor Building Arrangement — Elevation −8200 mm



NOTES:

1. COLUMN DIMENSIONS ARE 2.0M X 2.0M (TYPICAL).
2. FLOOR SLAB THICKNESS IS 0.6M.
3. MAIN BEAM DIMENSIONS ARE 1.5M X 1.8M.

Figure 2.15.10d Reactor Building Arrangement—Elevation −5100 mm



NOTES:

1. "•" DENOTES DOORS WITH RAISED SILLS.
2. "ᗡ" DENOTES WATERTIGHT DOORS TO PREVENT WATER ENTERING ROOMS FROM CORRIDORS.
3. COLUMN DIMENSIONS ARE 2.0M X 2.0M (TYPICAL).
4. FLOOR SLAB THICKNESS IS 0.6M.
5. MAIN BEAM DIMENSIONS ARE 1.5M X 1.8M.

Figure 2.15.10e Reactor Building Arrangement—Elevation -1700mm

2.15.11 Turbine Building

Design Description

The Turbine Island consists of two nonsafety related seismic category II buildings that are located adjacent to the plant safety related seismic category I control building.

The turbine building is a large heavy structure that is 108 m long, 56 m wide and 49 m high in its tallest region. It is provided with main and auxiliary bridge cranes. The turbine building houses the main turbine generator and other plant power cycle equipment and auxiliaries.

The electrical building is a relatively light structure that is 72 m long, 13 m wide and 18 m high. It houses various plant support systems and equipment such as non-divisional switchgear and chillers.

Turbine Building

The turbine building is supported on a two-level foundation mat which also supports the turbine generator pedestal. The building is a structural steel frame building with steel columns supported on top of the basemat. Exterior columns are provided with structural bracing to resist tornado and seismic loads.

Main interior walls are poured in place reinforced concrete walls which also act as shear walls. Exterior walls are poured in place reinforced walls below grade, non-structural precast concrete panels between grade and the operating floor and metal siding above the operating floor.

The floors of turbine building are reinforced concrete with the floor support system consisting of structural steel beams or girders and metal deck. These floors are designed as diaphragms for lateral load transfer. A gap of about 50 mm (2") is provided between turbine building floors and the turbine generator pedestal.

The roof is built-up roofing on metal decking supported on roof trusses and roof purlines. The roofing system is provided with steel bracing for transfer of lateral loads.

The turbine building shall be designed as a seismic Category II structure with seismic loads based on Uniform Building Code (UBC) requirements. However, being adjacent to the control building, which is a Seismic Category I structure, the building is designed to not collapse under tornado loads and seismic loads corresponding to SSE of 0.3g horizontal ground acceleration. Since structural integrity and not the functional integrity is required under extreme environmental conditions, some plastic deformations of the structure is permissible.

Turbine Generator Pedestal

The turbine generator is supported either on a conventional reinforced concrete or composite steel-concrete pedestal founded on the common basemat. The turbine generator pedestal is designed as a ductile moment resisting space frame structure. Separation joints are provided between the pedestal and the turbine building floors around it, to prevent transfer of vibrations to the building.

The turbine generator pedestal is a non-seismic structure and has no enhanced seismic requirements beyond those imposed by the building codes.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.15.11 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the Turbine Building.

Table 2.15.11: Turbine Building

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Aceptance Criteria
1. The Turbine Building shall be designed as a seismic category II structure and the building will not collapse under seismic loads corresponding to SSE of 0.3g horizontal ground acceleration.	1. Review design documentation and perform visual inspections of the structure and features.	1. Building meets the Uniform Building Code (UBC) requirements and has the necessary seismic capability.
2. In the event of a design basis tornado, there will be no turbine building damage that would result in any consequential damage to adjacent safety related buildings or their enclosed safety related equipment.	2. Review the datailed design documentation to confirm that any tornado generated missile will not damage adjacent safety related structures or components.	2. Consequential damage to safety related equipment in adjacent buildings will not occur.
3. The detailed structural design will be based on required applicable ACI and AISC codes and UBC. Loading condition will be based on appropriate site design data.	3. Confirmation that the as-built design is in compliance with required applicable ACI, AISC and UBC requirements and is based on appropriate site design data.	3. The Turbine Building design documentation will be reviewed.
4. Separation joints are provided between the turbine generator pedestal and the turbine building floors around it, to prevent transfer of vibrations to the building.	4. Perform dimensional inspections and check the separation joints.	4. A gap of about 50 mm (2") should be provided between turbine building floors and the turbine generator pedestal.

2.15.12 Control Building

Design Description

The Control Building (CB) is the building that houses the main control room, control equipment, and operations personnel for the Reactor and Turbine Islands. The Control Building is located between the Reactor and Turbine Buildings.

In addition to the control room and operations personnel, this building houses the essential electrical, control and instrumentation equipment, essential switch gear, essential battery rooms, the CB heating and air conditioning (HVAC) equipment, Reactor Building component cooling water pumps and heat exchangers, and the steam tunnel.

The general building arrangement, including watertight doors and sills for doorways where needed for flood control, is shown in Figures 2.15.12a through 2.15.12g.

The CB is a Seismic Category I structure designed to resist seismic loadings and to provide protection for flooding, tornado wind, and tornado missiles.

The CB is constructed of reinforced concrete with steel truss roof. The CB has two stories above the grade level and four stories below. The building shape is rectangle. Major nominal dimensions are as follows:

Overall height above top of basemat	30.5 m
Overall planar dimensions (outside)	
0°-180° direction	24.0 m
90°-270° direction	56.0 m
Thickness of Outer Wall	
from -8.2m TMSL to 17.15m TMSL	1.0 m
from 17.15m TMSL to 22.2 m TMSL	0.6 m
Thickness of Steam Tunnel	
Walls, Floors, and Ceiling	1.6 m
Thickness of Walls supporting Steam Tunnel	1.6 m

The CB is a shear wall structure designed to accommodate all specified seismic loads with its perimeter walls and steam tunnel walls together with their supporting elements. Therefore, frame members such as beams or columns are designed to accommodate deformations of the walls in case of earthquake condition. The columns provide vertical weight bearing capability. Column sized and floor slab thicknesses are also provided in the general building arrangement figures. With major dimensions defined as listed above for specified reinforced concrete materials and design procedures, the dynamic characteristic of the CB structure is defined. Seismic adequacy of the detailed site-specific control building design will be evaluated using the dimensional characteristics noted above and approved analytical procedures and methodology for dynamic analysis of structures. This work will be in compliance with the ACI and AISC codes governing design of reinforced concrete structures and steel structures for nuclear power plants. Detailed analyses of the site specific control building design will utilize appropriate site data for seismic events, floods, tornados, winds and other loading conditions.

To protect against external flood damage, the following design features are provided:

(1) Wall thickness below flood level greater than 0.6m.

(2) Water stops provided in all construction joints below grade.

(3) Watertight doors and piping penetrations installed below flood level.

(4) Waterproof coating on exterior walls.

(5) Foundations and walls of structures below grade are designed with water stops at expansion and construction joints.

(6) Roofs are designed to prevent pooling of large amounts of water.

To protect against internal flood damage, the following design features are provided:

(1) Elevation differences and divisional separations from remainder of the CB.

(2) Drainage system to divert water to assigned floor and location.

(3) Sills for doorways as needed to provide flood control.

(4) Watertight doors installed below internal flood level.

(5) Wall thickness below internal flood level greater than 0.6m.

Inside the steam tunnel is the mainsteam piping, the mainsteam drain line, and the feedwater piping. There is no penetration from the steam tunnel into the control building. Any high energy line breaks inside the steam tunnel will vent out to the Turbine Building. All standing water will collect in the large volumes in the lower portions of the steam tunnel at the Reactor Building or Turbine Building ends.

On Floor B1F, there are fire hose stands and reactor cooling water (RCW) piping. It is designed that any rupture of the fire hose stand will leak onto the floor and drain to the -8200 level by floor drains. Sills will be provided at doorways to prevent the entry of standing water into the control room complex. The RCW piping runs vertically in a concrete pipe chase. No flooding outside this pipe chase is possible.

On the floor where computer room located, there are fire hose stands, RCW piping, and other piping systems. Varying amounts of standing water are expected upon a rupture of any of these systems. Maximum water height corresponds to the height of the door sills. Sills will be provided at doorways to prevent water from crossing divisional boundaries. Similar arrangements and designs are also provided for other floors for floods protection.

During normal operation, the concrete surrounding the steamline tunnel provides shielding so that operator doses are below the value associated with uncontrolled, unlimited access. The outer walls of the control building are designed to attenuate radiation from radioactive materials contained within the reactor building and from possible airborne radiation surrounding the control building following a LOCA. The walls provide shielding to limit the direct-shine exposure of control room personnel following a LOCA. Shielding for the outdoor air cleanup filters also is provided to allow temporary access to the mechanical equipment area of the control building following a LOCA, should it be required.

The control building is not a vented structure. The exposed exterior roofs and walls of the structure are designed for the required pressure drop. Tornado dampers are provided on all air intake and exhaust openings. These dampers are designed to withstand the specified negative pressure.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.15.12 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the control building.

Table 2.15.12: Control Building

Inspections, Tests, Analyses and Acceptance Criteria

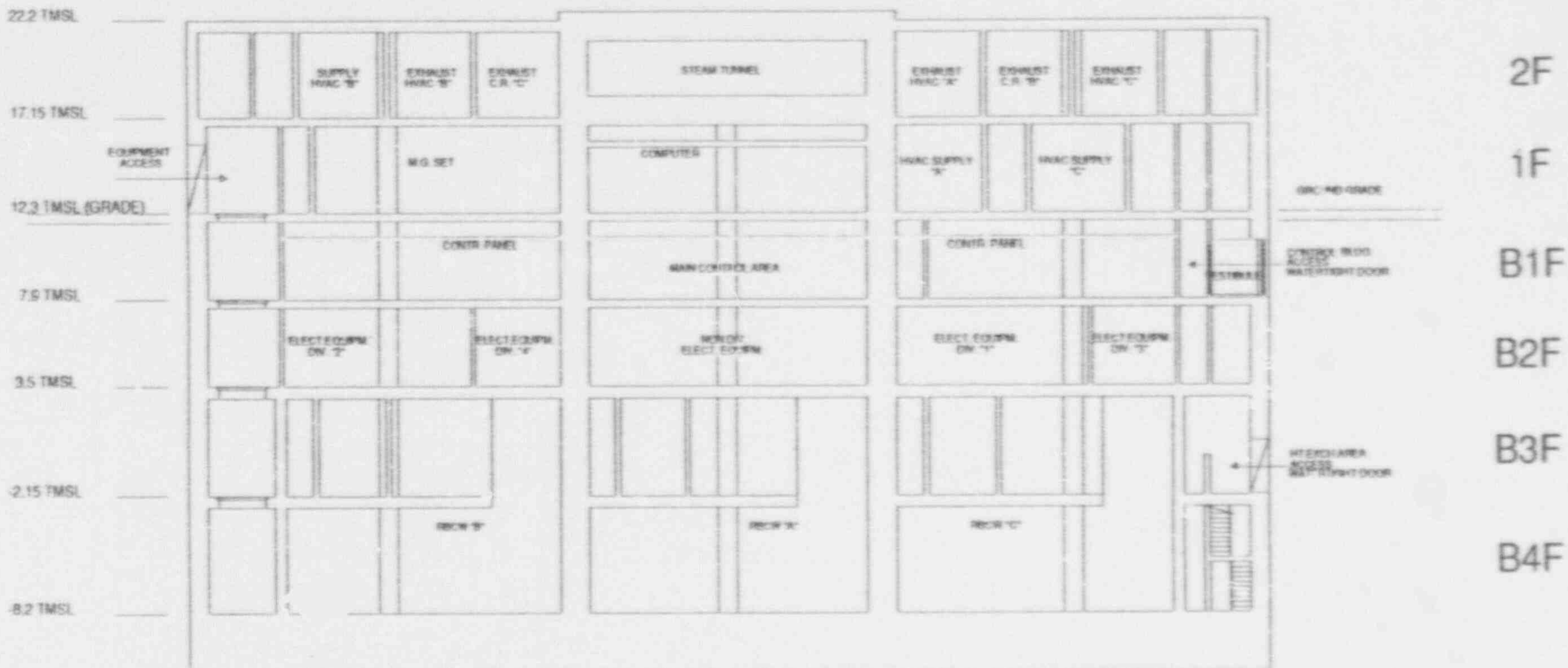
Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Control building general arrangement is shown in Figures 2.15.12a through 2.15.12g.	1. Plant walk through* to check and verify requirements are met.	1. Per Figures 2.15.12a through 2.15.12g.
2. Design features are provided to protect against design basis internal and external floods.	2. Review construction records and perform visual inspections of the flood control features.	2. For external flooding: a. Exterior wall thickness below flood level greater than 0.6m. b. Water stop. c. Watertight door and piping penetrations below flood level. d. Waterproof coating on exterior walls. e. Foundations and walls of structures below grade are designed with water stops at expansion and construction joints. f. Roofs are designed to prevent pooling of large amounts of water. For internal flooding: a. Elevation differences and divisional separation of the mechanical functions from the remainder of the CB. b. Drainage system to divert water to assigned floor and location. c. Sills for doorways as needed to provide flood protection. d. Watertight doors installed below internal flood level. e. Wall thickness below internal flood level greater than 0.6m. f. Steam tunnel has no penetrations from the steam tunnel into the control building. Any high energy line or feedwater piping breaks inside the steam tunnel will vent out to the Turbine Building.

* Plant walk through is intended to include visual inspection of the as-built facility and (as-needed) dimensional measurements.

Table 2.15.12: Control Building (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

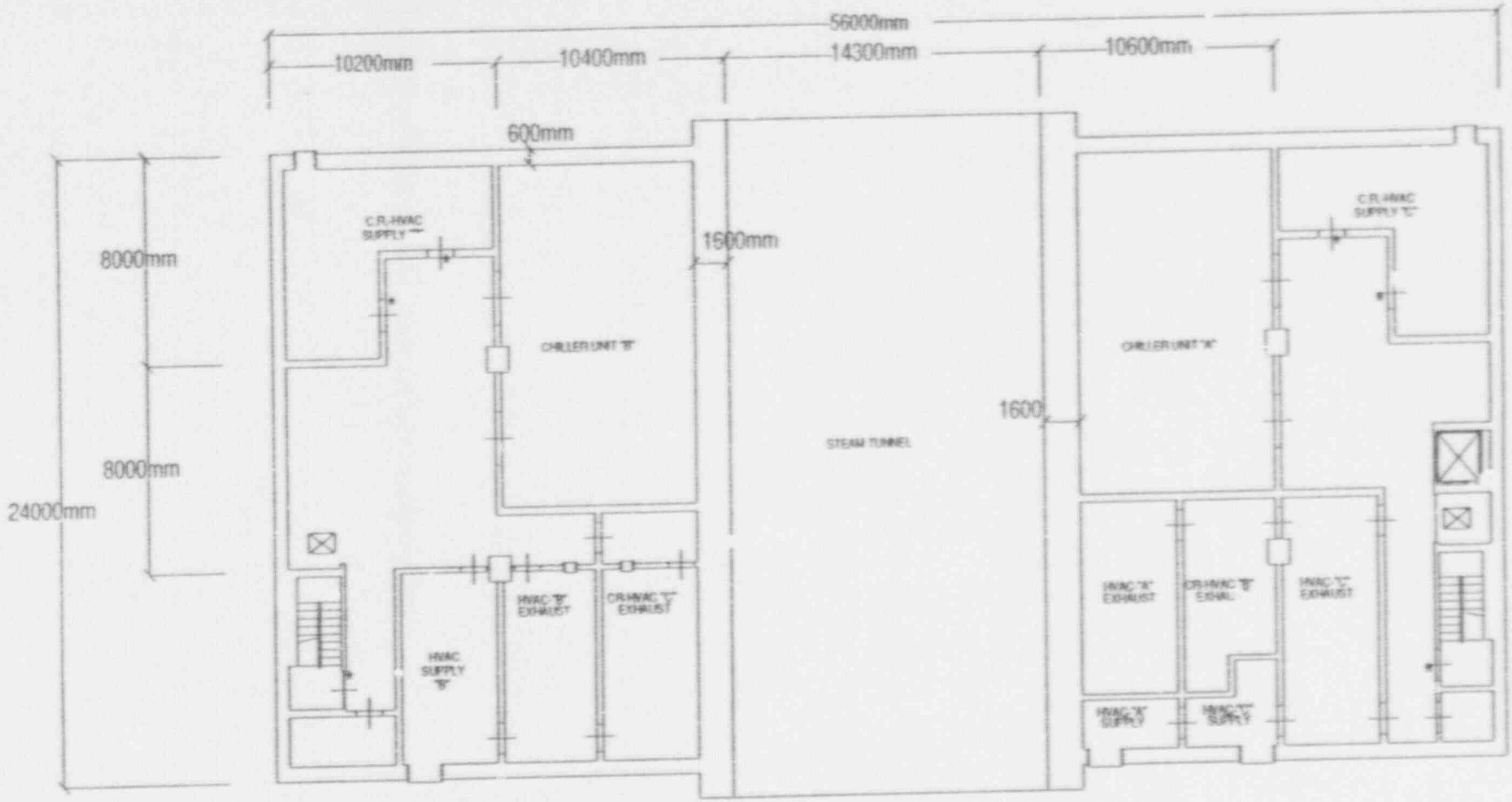
Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3. The Control Building is designed to have adequate radiation shielding to protect operating personnel during operation and following a LOCA.	3. Performed dimensional inspections of the Control Building walls, ceiling, floors, and other structural features.	3. The concrete thickness for the steam tunnel wall, floor and ceiling shall be greater than 1.6m. The steam tunnel interface structure and control building wall below the steam tunnel should have a combined thickness of 1.6m, i.e. in any line-of-sight from the control room, the total thickness of concrete between the observer and the steam lines must be 1.6m or greater.
4. The CB is designed to protect against design basis tornado and tornado missiles.	4. Review construction records and perform visual inspections and dimensional checks (as-needed) of the tornado protection features.	4. For tornado a. Roof and walls above grade designed greater than 0.5m. b. HVAC dampers designed for differential pressure > 1.46 psi. c. HVAC dampers have tornado missile barriers.
5. The CB is designed as a Seismic Category I structure and has major dimensions defined in the certified design.	5. Plant walk through to check and verify CB building major dimensions including column sizes and floor slab thickness. Review final design record for material properties site input data and analytical procedures and methodology for seismic analysis. Visual inspections of structures and review of as-built documentation will be conducted to assess compliance with the certified design commitments.	5. Structures have dimensions compatible with data in the certified design (Figures 2.15.12a through 2.15.12g).
6. The detail structural design will be based on ACI and AISC codes and will use site data for seismic events, floods, tornadoes winds and other loading conditions.	6. The control building design documentation will be reviewed.	6. Confirmation that the as-built design is in compliance with ACI and AISC requirements and is based on appropriate site design data.



Note: Roof thickness is 300 mm
Steam Tunnel roof thickness is 1600 mm

Figure 2.15.12a CONTROL BUILDING ELEVATION (90° - 270°)

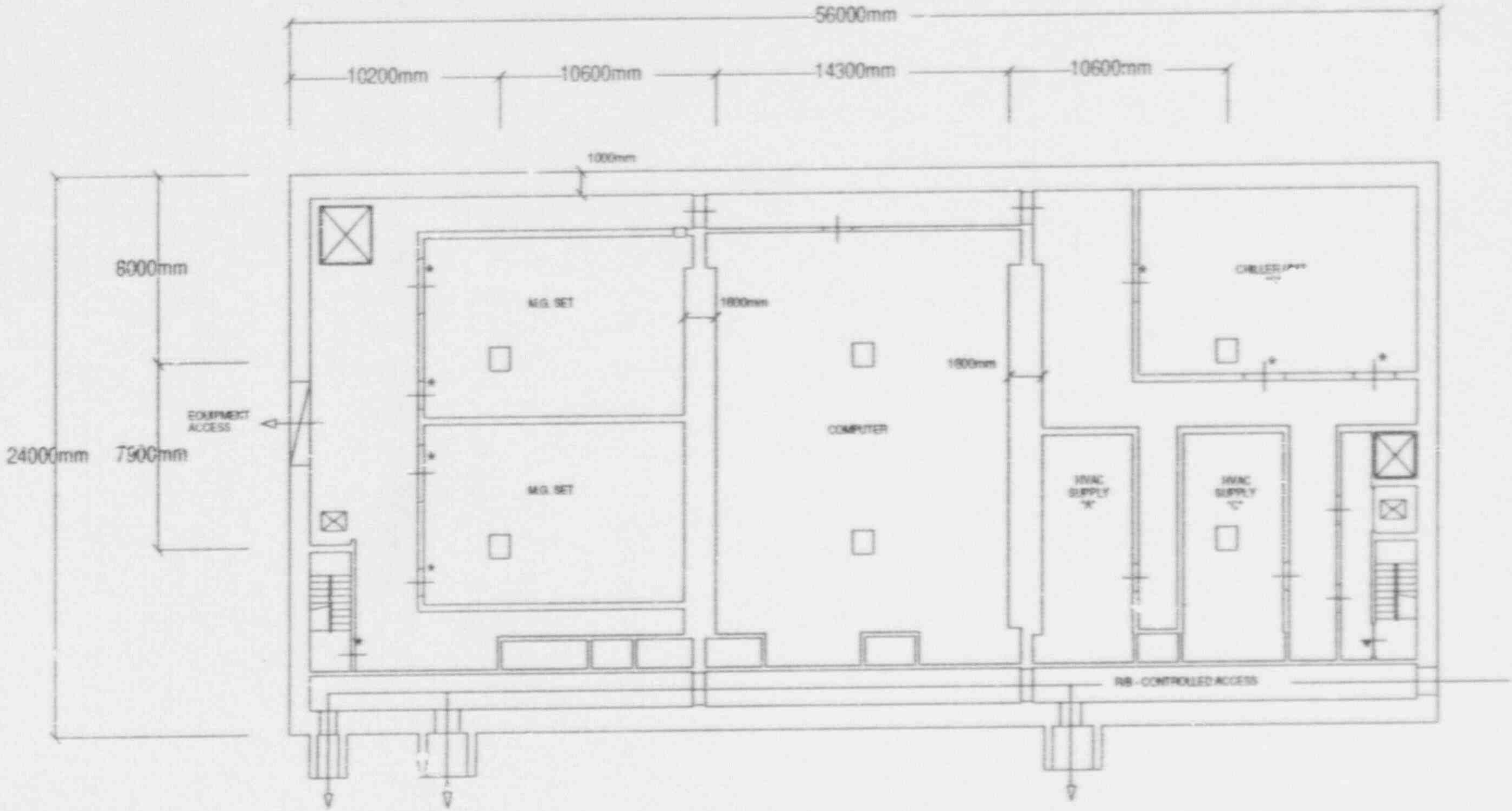
ELEVATION 17150mm TMSL



Notes: Doors marked with a * have raised sills
Floor slab is 400mm thick
Columns are 1000x1000mm typical

Figure 2.15.12b Control Building - Floor 2F

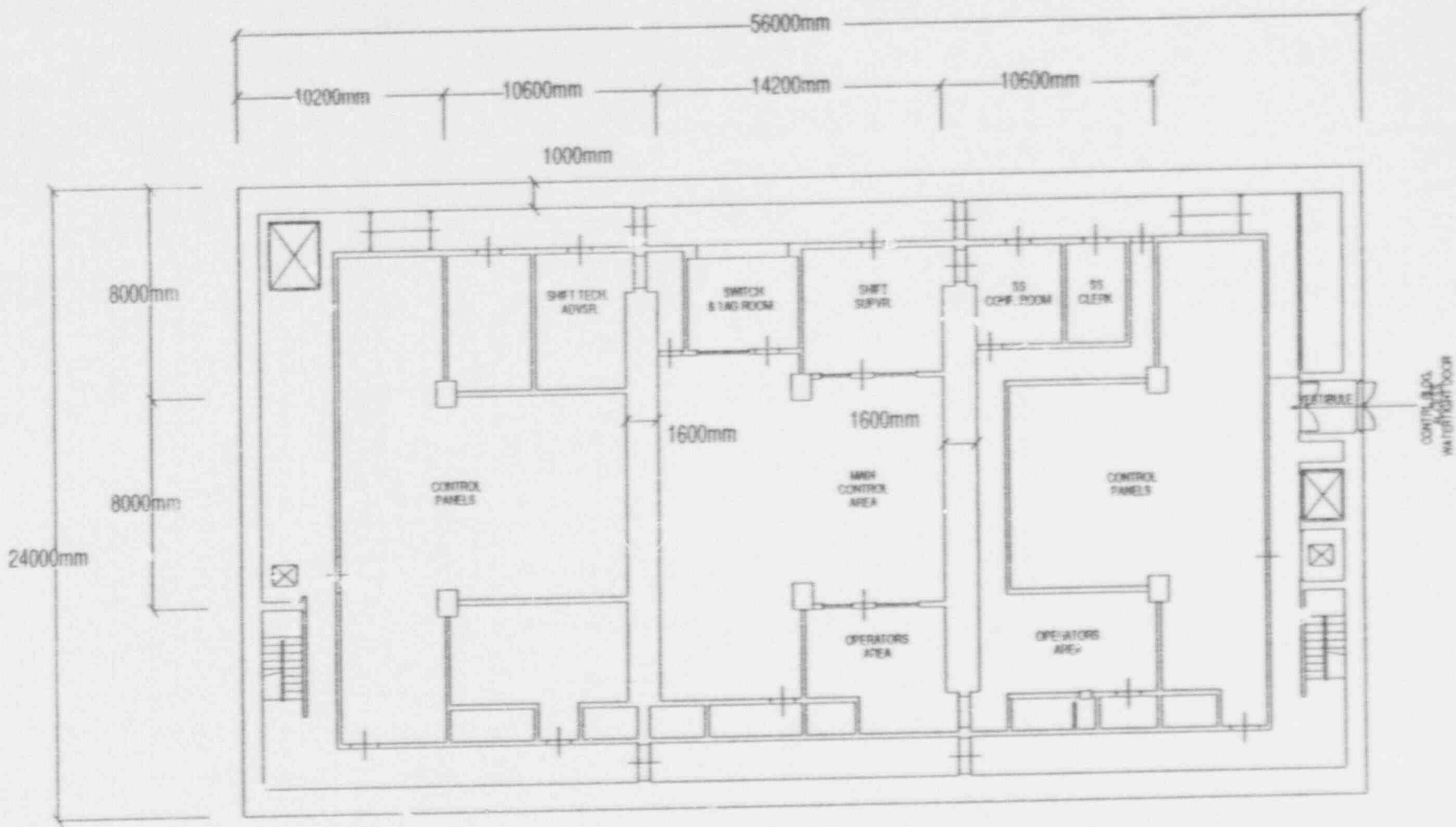
ELEVATION 12300mm TMSL



Notes: Doors marked with a * have raised sills
Columns are 1000x1000mm typical
Floor slab is 400mm thick

Figure 2.15.12c Control Building Floor 1F - Ground Grade

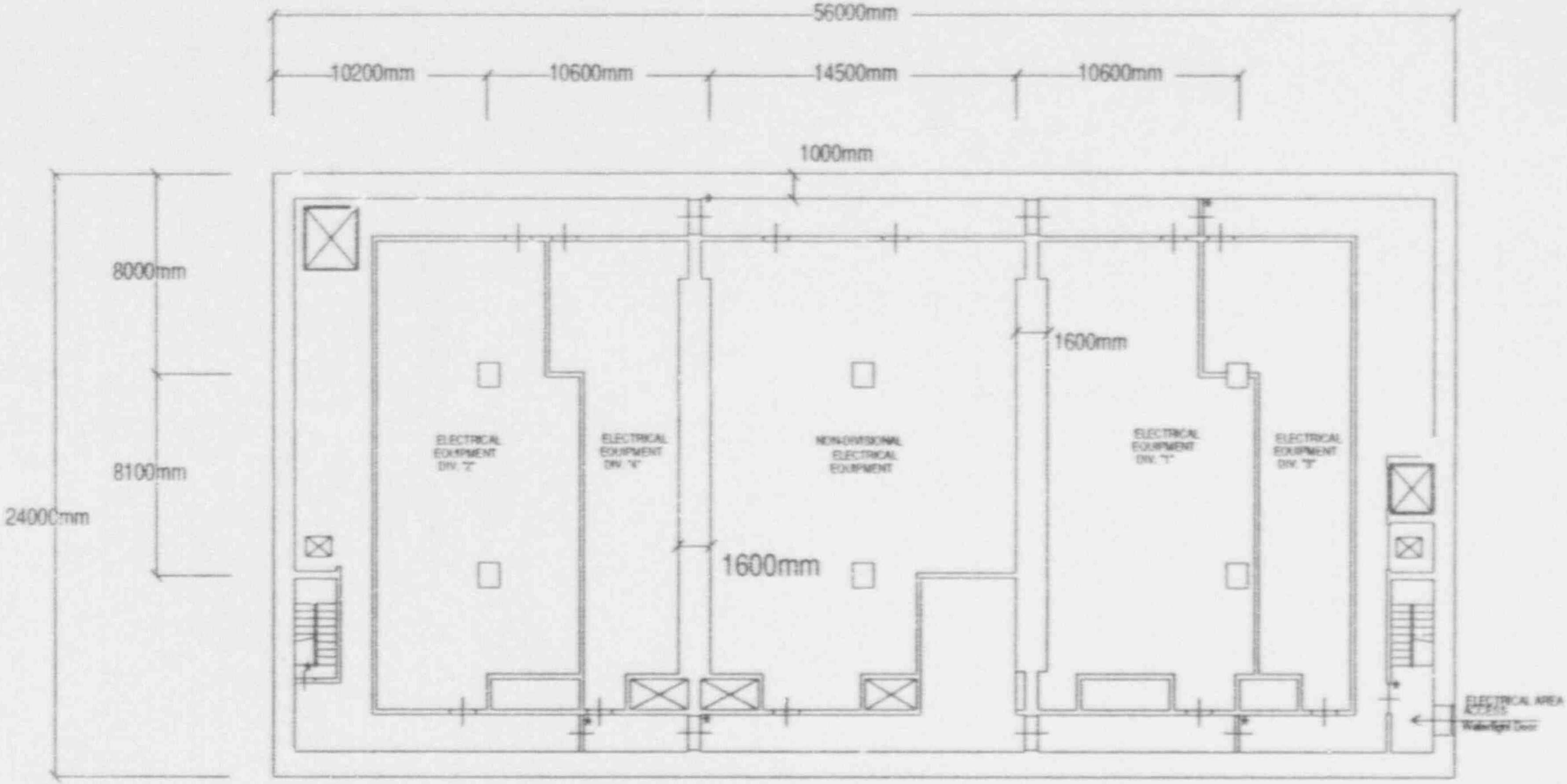
ELEVATION 7900mm TMSL



Notes: Floor slab is 400mm thick
Columns are 1000x1000mm typical

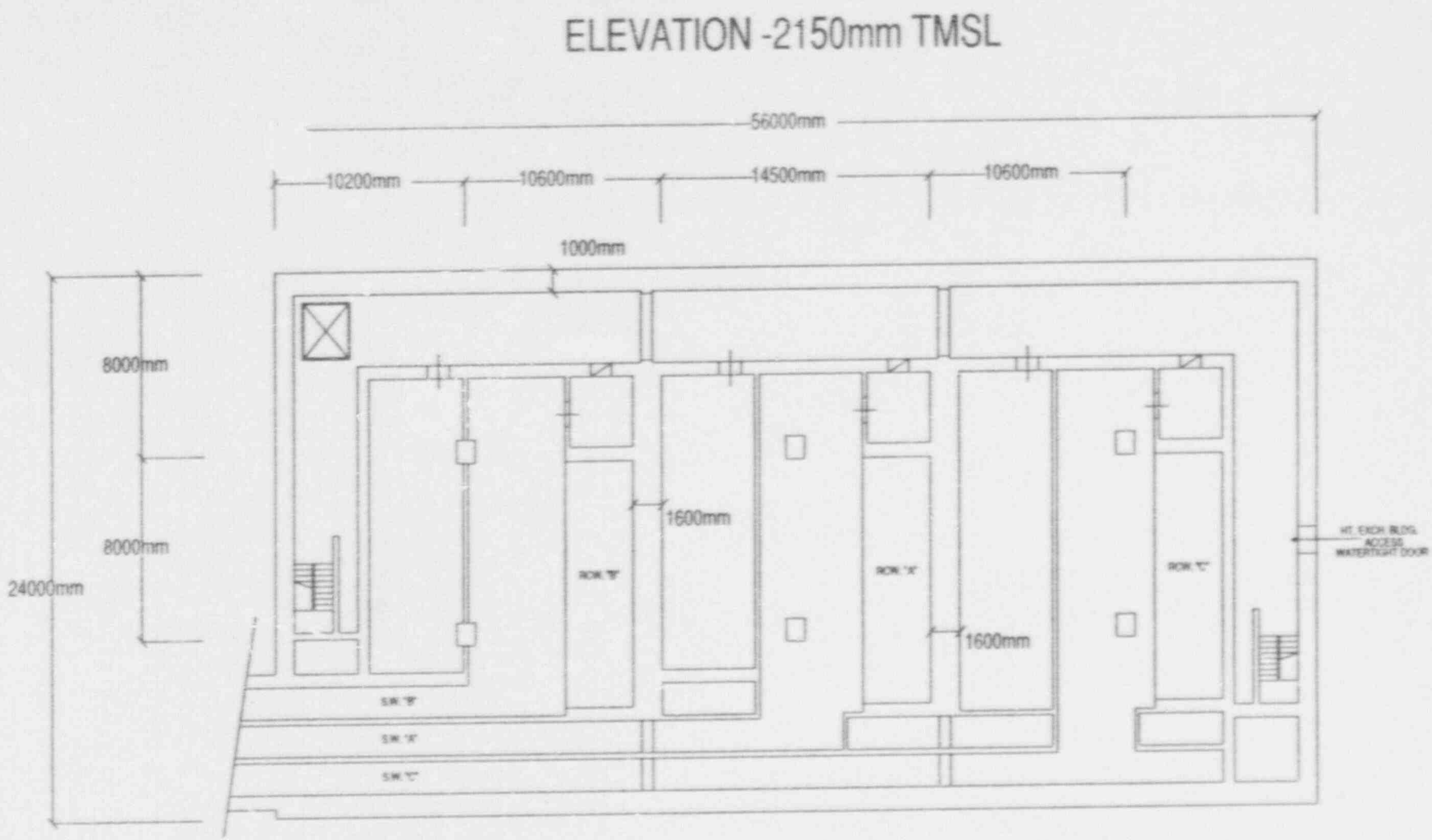
Figure 2.15.12d Control Building Floor B1F

ELEVATION 3500mm TMSL



Notes: Doors marked with a * have raised sills
Floor slab is 400mm thick
Columns arє 000x1000mm typical

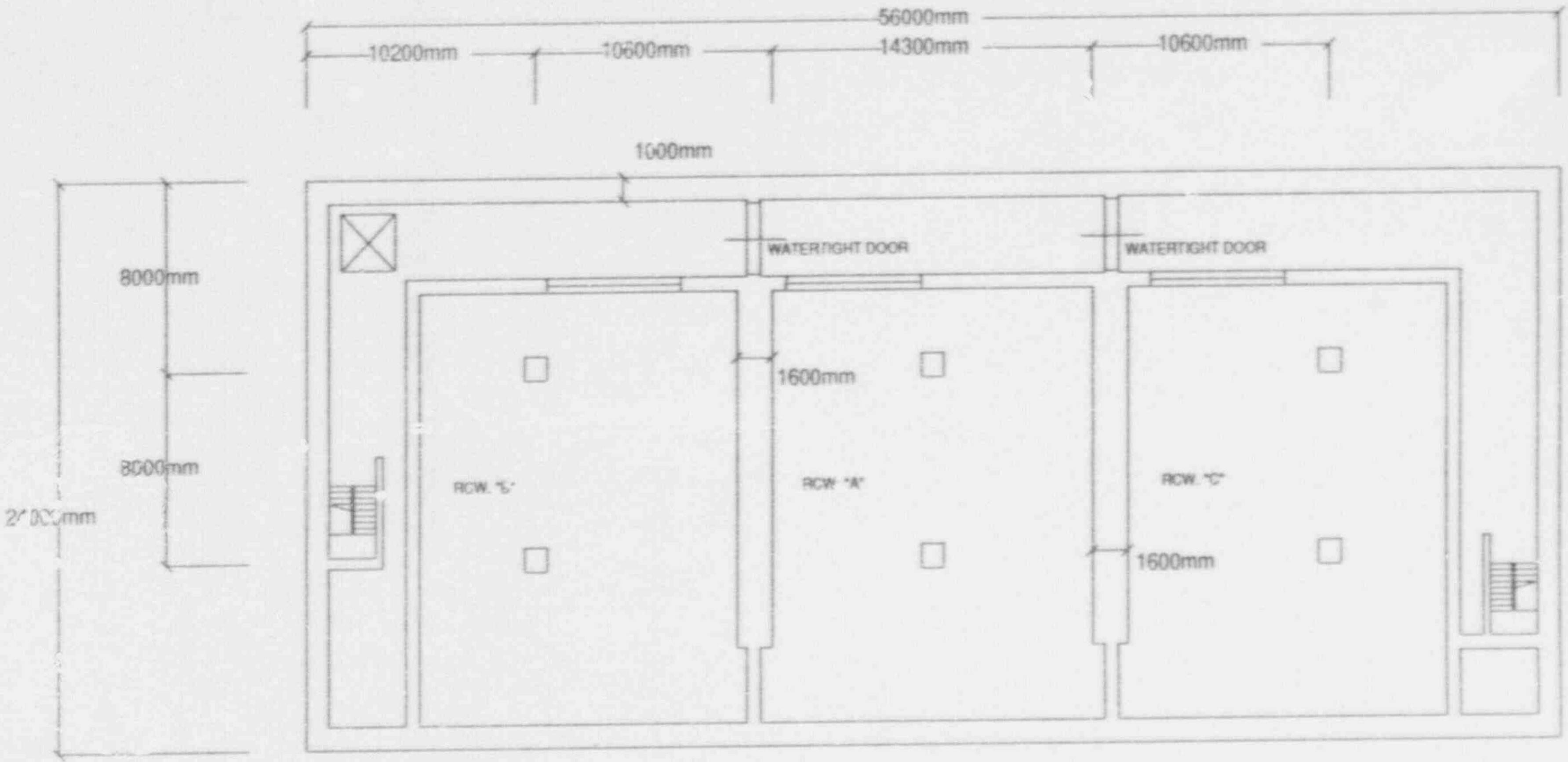
Figure 2.15.12e Co[?]ol Building Floor B2F



Notes: Columns are 1000x1000mm typical
Floor slab is 400mm thick

Figure 2.15.12f Control Building Floor B3F

ELEVATION -8200mm TMSL



Notes: Columns are 1000x1000mm typical
Basemat is 2600mm thick (min)

Figure 2.15.12g Control Building Floor B4F

2.15.13 Radwaste Building

Design Description

The Radwaste Building (RWB) is designed to house the radioactive waste management system and its facilities. The RWB consists of superstructure which is a non-safety class and non-seismic structure, and substructure which is safety class 3 and seismic category I structure.

The RWB is built on the 54.2mx41.2m with 2.5m thickness reinforce concrete basemat. The substructure is from the basemat up to about 13.8m height, the grade level, and has exterior walls thickness of 1.1m,slab thickness of 2.5m and typical column sizes of 1mx1m. The super structure built on top the substructure has exterior walls thickness of 0.6m, slab thickness of 0.8m and typical column sizes of 1mx1m. The typical roof thickness is 0.5m. The RWB is built of reinforced concrete and has a total height of approximately 29.5m.

Seismic Consideration

With major dimensions defined as described above for specified reinforced concrete materials and design procedures, the dynamic characteristic of the RWB structure is defined. Seismic adequacy of the detailed site-specific RWB design will be evaluated using the dimensional characteristic noted above and approved analytical procedures and methodology for dynamic analysis of structures. This work will be in compliance with the required applicable ACI and AISC codes governing design of the reinforced concrete and steel structures for nuclear power plants. Detailed analyses of the site-specific RWB substructure design will utilize appropriate site data for seismic events, floods and other loading conditions.

The non-seismic category reinforced concrete portion of the superstructure is designed according to the Uniform Building Code (UBC).

Flooding Protection

To protect against external flood damage, the following design features are provided:

(1) water stops provided in all construction joints below grade.

(2) watertight doors and piping penetrations installed in external walls below flood level.

(3) waterproof coating on exterior walls below grade.

(4) foundations and walls of structures below grade are designed with water stops at expansion and construction joints.

(5) roofs are designed to prevent pooling of water.

(6) building will be sited so that the design basis maximum flood level is one foot (0.3m) below grade.

Tornado and Missile Consideration

The substructure is protected against tornado and missile being built below the grade level. The superstructure is designed such that in the event of a design basis tornado, there will be no RWB damage that would result in any consequential damage to adjacent safety related buildings or their enclosed safety related equipment.

Radiation Shielding

The RWB is designed with rooms and cubicles to segregate radioactive plant systems and components from other plant operating areas. Shielding is provided such that radiation doses to plant personnel and members of the public resulting from operation and maintenance of the plant are as low as reasonably achievable. The RWB is designed to ensure that areas containing equipment that may require manual operation to mitigate or recover from an accident can be accessed without subjecting operators to excessive doses. Section 3.7, Radiation Protection, is referred to for further descriptions.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.15.13 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the Radwaste Building.

Table 2.15.13: Radwaste Building

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Design features are provided to protect against design basis external floods.	1. Review construction records and perform visual inspections of the flood control features.	1. For external flooding: a. Water stops provided. b. Watertight doors and piping penetrations below flood level. c. Water proof coating on exterior walls. d. Foundations and walls of structures below grade are designed with water stops at expansion and construction joints. e. Roofs are designed to prevent pooling of water. f. Building will be sited so that the design basis maximum flood level is one foot(0.3m) below grade.
2. The substructure of RWB is a Seismic Category I structure and has major dimensions defined in the certified design.	2. Plant walk through to check and verify RWB major dimensions including column sizes and floor slab thickness. Review final design record for material properties, site input data and analytical procedures and methodology for seismic analysis. Visual inspections of structures and review of as-built documentation will be conducted to assure compliance with the certified design commitments.	2. Structures have dimensions compatible with data in the certified design.
3. The detail structural design will be based on required applicable ACI and AISC codes and will use site data for seismic events, floods, tornados, winds and other loading conditions.	3. The Radwaste Building design documentation will be reviewed.	3. Confirmation that the as-built design is in compliance with required applicable ACI and AISC requirements and is based on appropriate site design data.
4. The RWB is designed to have adequate radiation shielding to ensure that the occupational radiation exposure to personnel will be kept as low as reasonably achievable (ALARA).	4. Perform visual inspections of the as-built RWB to confirm that all design features are built.	4. Per Section 3.7, Radiation Protection.

Table 2.15.13: Radwaste Building (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. The superstructure of RWB is designed such that in the event of a design basis tornado, there will be no RWB damage that would result in any consequential damage to adjacent safety related buildings or their enclosed safety related equipment.	5. Review the detailed design documentation to confirm that any tornado generated missile will not damage adjacent safety related structures or components.	5. Consequential damage to safety related equipment in adjacent buildings will not occur.

2.15.14 Service Building

Design Description

The Service Building is located closely adjacent to the Control Building. This building is the common access and control point to the Control Building, Turbine Building and Reactor Buildings.

The service building is a non-safety and non-seismic classified structure provided to house service facilities such as technical support center, instrument repair room, health physics, monitor, laundry, men change room, women change room and lunch room. It is designed that in the event of a design basis tornado, there will be no service building damage that would result in any consequential damage to adjacent safety related buildings or their enclosed safety related equipment.

The service building is designed with rooms and hallways to segregate personnel going to clean or radioactive plant areas. This building contains the health physics laboratory which has incorporated its own separate ventilation point and self shielded hot facility. Section 3.7, Radiation Protection, is referenced to for further details of description.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.15.14 provides a definition of the inspections, test, and/or analyses, together with associated acceptance criteria which will be undertaken for the Service Building.

Table 2.15.14: Service Building

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Service Building provides an entrance to the building on the ground level and four accesses to adjacent buildings on various levels.	1. Visual inspection of the structure and features.	1. Confirmation that the as-built features are in compliance with the design.
2. Health physics lab. contains self shield hot facility and separate ventilation point.	2. Review the Service Building design documentation.	2. Per Section 3.7, Radiation Protection.

2.16 Yard Structures and Equipment

2.16.1 Stack System

Design Descriptio.,

The Stack System consists of a steel pipe with its outlet 76 meters above grade and supported in a steel tubular framework mounted on top of the Reactor Building and rises.

The design of the stack is Safety Class 3, Seismic Category I mounted on a Seismic Category I support.

The stack vents the Reactor Building, Turbine Building, Radwaste Building, Control Building and the Service Building potentially radioactive exhaust.

The stack releases are monitored for radioactivity.

Inspections, Tests, Analyses and Acceptance Criteria

Table 2.16.1 provides a definition of the inspection, test, and/or analyses together with the associated acceptance criteria which will be undertaken for the Stack System.

Table 2.16.1: Containment Internal Structures

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Stack System consists of a steel pipe supported within a tubular steel framework mounted on top of the Reactor Building with a radiation monitor support.	1. Review the as-built Stack System construction records and conduct onsite inspections to confirm the stack installation matches the design documents.	1. As-built Stack System installation conforms to the design requirements, is connected to the exhaust systems of the Reactor, Turbine, Radwaste, Control and Service Buildings and supports the radiation monitor equipment.
2. The Stack System is designed to Safety Class 3 and Seismic Category I requirements.	2. Review the as-built documentation and verify the stack system is designed, fabricated and installed to meet Safety Class 3 and Seismic Category I requirements.	2. Confirm the as-built documentation meets the code requirements for Safety Class 3 and Seismic Category I design, fabrication and installation.
3. The Stack System releases potentially radioactive exhaust from the Reactor, Turbine, Radwaste, Control and Service Buildings. The top of the stack is 76 meters above grade.	3. Determine from as-built records and visual inspection that the stack height is 76 meters above grade and verify the documentation shows this height to be acceptable for potential radioactive releases during normal reactor operation.	3. Confirm the stack height is 76 meters above grade and meets code requirements for radioactive releases from this elevation.

2.16.2 Oil Storage and Transfer System

Design Description

The Oil Storage and Transfer System consists of three fuel storage facilities: Emergency Diesel Generator System with three independent fuel storage tanks, pumps, piping and day tanks; Combustion Turbine Generator with one diesel fuel storage tank, transfer pump and day tank; and the House Boiler System with one fuel oil tank, pump and piping.

Emergency Diesel Generator Fuel Storage and Transfer System

The design of the emergency diesel fuel and transfer system including: pumps, piping, controls and instrumentation is Safety Class 2. The storage tank and transfer pump are mounted within a Seismic Category I lined concrete pit with cover capable of providing protection from natural phenomena.

Each emergency diesel generator fuel transfer pump and controls are provided with Class 1-E electric power from the electrical division they serve. Each transfer pump has a flow capacity of 200% of diesel engine fuel consumption at full load.

The capacity of the emergency diesel fuel storage tank and the capacity of the day tank are described in Section 2.12.13 Emergency Diesel Generator System (Standby AC Power Supply). Diesel fuel is transferred by gravity from the day tank to the diesel engine. The day tank recirculation and overflow pipe with anti-siphon device drains back to the diesel fuel storage tank. The day tank low level switch actuates the transfer pump start signal when 60-minutes of diesel fuel remains in the day tank. A high level switch in the day tank stops transfer pump operation. Controls for the tank levels and transfer pump operation are located in the main control room.

Combustion Turbine Generator Fuel Storage and Transfer System

The non-safety Combustion Turbine Generator diesel fuel storage tank and transfer pump are anchored to a diked concrete pad located adjacent to the Electric Building adjoining the Turbine Building. The storage tank has a capacity of 7-days consumption of fuel by the combustion turbine at full load and the day tank has a capacity of 8-hours of combustion turbine operation. The transfer pump has a flow capacity of 200% of the combustion turbine diesel fuel consumption. The day tank serves the starting diesel fuel system and the combustion turbine fuel system. The day tank recirculation and overflow pipe with anti-siphon device drains back to the diesel fuel storage tank. The day tank low level switch actuates the transfer pump start signal when 60-minutes of diesel fuel remains in the day tank. A high level switch in the day tank stops transfer pump operation. Controls for the tank levels and transfer pump operation are located in the main control room

AC Electric power is non-class 1E and is supplied from one plant investment protection (PIP) bus.

The non-safety combustion turbine diesel fuel storage tank and transfer pump are mounted on a diked concrete pad outside the Electrical Building.

House Boiler Fuel Storage and Pump System

The non-safety house boiler fuel oil storage tank and pump are mounted on a diked concrete pad outside of the Electric Building which adjoins the Turbine Building. The storage tank has a capacity of 7 days fuel consumption at maximum oil burner firing rate. The fuel oil pump is capable of supplying the maximum fuel oil demand of the burner. A pressure relief return valve and return pipe are connected to the fuel oil storage tank to return any excess fuel oil flow to the tank. Controls for the tank levels and fuel oil pump operation are mounted in a local panel in the House Boiler Room.

Inspections, Tests, Analyses and Acceptance Criteria

The following tables provide the definition of the inspection, tests, and/or analyses with the associated acceptance criteria which will be undertaken for the Fuel Oil Storage and Transfer Pump Systems identified.

Table	System
2.12.13	Emergency Diesel Generator System (Standby AC Power Supply) ITAAC Item 9
2.14.2a	Emergency Diesel Generator Fuel Storage and Transfer System
2.14.2b	Combustion Turbine Generator Fuel Storage and Transfer System
2.14.2c	House Boiler Fuel Oil Storage and Pump System

Table 2.16.2a: Emergency Diesel Generator Fuel Storage and Transfer System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Emergency Diesel Generator Fuel Storage and Transfer System consists of three tanks each contained within a lined concrete pit located adjacent to the Reactor Building quadrant containing the diesel generator and day tank served. Independent transfer pump, piping and controls are located adjacent to each diesel oil storage tank.	1. Review the as-built Emergency Diesel Generator Fuel Storage and Transfer System documentation and visually inspect the installation to verify the tanks and transfer pumps of each division are separately located and serve the appropriate diesel generator division.	1. As-built Emergency Diesel Generator Fuel Storage and Transfer Pump installations conform to the design documentation and are located adjacent to the Reactor Building quadrant in which the diesel generator division served.
2. The diesel fuel oil tanks are anchored within a lined concrete pit. The pit and cover are designed to Safety Class 2 and Seismic Category I requirements. The transfer pump and piping are also designed Safety Class 2 Seismic Category I.	2. Review the as-built documentation and by visual inspection verify the diesel oil storage tanks are each anchored within a lined concrete pit. The lined concrete pit is designed, fabricated and installed to meet Safety Class 2 and Seismic Category I requirements. Also verify that each transfer pump and associated piping meet the Safety Class 2 and Seismic Category I requirements.	2. Confirm the as-built documentation and inspection of the installation shows each diesel fuel storage tank is anchored within a lined concrete pit that meets the Safety Class 2 and Seismic Category I requirements. Also confirm the transfer pumps and piping are designed, fabricated and installed to meet Safety Class 2 and Seismic Category I requirements.
3. Each diesel oil transfer pump's motor, controls and instrumentation are rated Class 1-E and are connected to the same class 1-E electrical power division as the diesel generator division served.	3. Review the as-built documentation and visually inspect the installation of each transfer pump's motor, controls and instrumentation to verify they are Class 1-E and are connected to the same Class 1-E electric power division as the diesel generator served.	3. Confirm each as-built transfer pump's motor, controls and instrumentation are designed, fabricated, installed and tested Class 1-E and are connected to the same Class 1-E division of electric power as the diesel generator division served.
4. The diesel oil transfer and day tank recirculation and overflow drain piping, control and instrument conduit supports are designed to meet Safety Class 2 and Seismic Category I requirements.	4. Review the as-built documentation and visually inspect the installation of the diesel oil transfer and day tank recirculation and overflow drain piping, control and instrumentation conduit supports to verify they are designed, fabricated and installed to Safety Class 2 and Seismic Category I requirements.	4. Confirm the as-built documentation shows the diesel oil transfer and day tank recirculation and overflow drain piping, control and instrument conduit supports are designed, fabricated, and installed to Safety Class 2 and Seismic Category I requirements.

Table 2.16.2a: Emergency Diesel Generator Fuel Storage and Transfer System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. Each diesel oil transfer pump and associated piping are designed to transfer the diesel fuel to the day tank at a rate of 200% of the rate the fuel is consumed by the diesel generator operating at full load.	5. Review the as-built documentation for the diesel fuel transfer pump rating and determine the flow rate of transfer from the diesel fuel oil storage tank to the day tank exceeds 200% of the fuel consumption of the diesel generator at full load.	5. Confirm each as-built diesel fuel transfer pump and associated piping are capable of transferring to the day tank 200% of the diesel engine fuel consumption at full load.
6. The controls and instrumentation of the Emergency Diesel Generator Fuel Storage and Transfer System are designed to be operable from the Main Control Room.	6. Verify by inspection the as-built controls and instruments for the diesel fuel storage and transfer system are operable from the Main Control Room.	6. Confirm the as-built controls and instruments for the Emergency Diesel Generator Fuel Storage and Transfer System are operable from the Main Control Room.
7. The diesel fuel transfer pump and piping is designed to supply diesel fuel from the storage tank to the day tank and periodically recirculate the diesel oil through return piping to prevent algae growth. The return pipe is provided with and anti-siphon device and also provides the overflow path from the day tank to the storage tank.	7. Verify by inspection of the as-built documentation the piping includes the recirculation and overflow piping with an anti-siphon device. Demonstrate the diesel oil can be recirculated.	7. Confirm the as-built piping includes the return and overflow pipe and anti-siphon device and observe the diesel oil can be recirculated from the day tank to the storage tank.

Table 2.16.2b: Combustion Turbine Generator Fuel Storage and Transfer System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Combustion Turbine Generator Fuel Storage and Transfer System consists of one storage tank anchored to a diked concrete pad located outside the Electrical Building adjacent to the Turbine Building, and a day tank. The transfer pump, piping and controls are located adjacent to the diesel fuel storage tank.	1. Review the as-built Combustion Turbine Generator Fuel Storage and Transfer System documentation and visually inspect the installation to verify the tank and transfer pump configuration matches the design documentation.	1. As-built Combustion Turbine Generator Fuel Storage and Transfer System installation conforms to the design documentation and is located outside the Electrical Building.
2. The diesel oil transfer pump's motor, controls and instrumentation are non-safety and are powered from the plant investment protection electric bus served by the Combustion Turbine Generator.	2. Review the as-built documentation and visually inspect the installation of the transfer pump's motor, controls and instrumentation to verify they are connected to the non-safety plant investment protection electric power bus served by the Combustion Turbine Generator.	2. Confirm the as-built transfer pump's motor, controls and instrumentation are connected to the plant investment protection electric power bus served by the combustion turbine generator.
3. Each diesel oil transfer pump and associated piping are designed to transfer the diesel fuel to the day tank at a rate of 200% of the rate the fuel is consumed by the combustion turbine generator operating at full load.	3. Review the as-built documentation for the diesel fuel transfer pump rating and determine the flow rate of transfer from the diesel fuel storage tank to the day tank exceeds 200% of the fuel consumption of the combustion turbine at full load.	3. Confirm each as-built diesel fuel transfer pump and associated piping are capable of transferring to the day tank 200% of the diesel fuel consumption of the combustion turbine at full load.
4. The controls and instrumentation of the Combustion Turbine Generator Fuel Storage and Transfer System are designed to be operable from the Main Control Room.	4. Verify by inspection the as-built controls and instruments for the Combustion Turbine Generator Fuel Storage and Transfer System are operable from the Main Control Room.	4. Confirm the as-built controls and instruments for the Combustion Turbine Generator Fuel Storage and Transfer System are operable from the Main Control Room.

Table 2.16.2b: Combustion Turbine Generator Fuel Storage and Transfer System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. The diesel fuel transfer pump and piping is designed to supply diesel fuel from the storage tank to the day tank and periodically recirculate the diesel oil through return piping to prevent algae growth. The return pipe is provided with and anti-siphon device and also provides the overflow path from the day tank to the storage tank.	5. Verify by inspection of the as-built documentation the piping includes the recirculation and overflow piping with an anti-siphon device. Demonstrate the diesel oil can be recirculated.	5. Confirm the as-built piping includes the return and overflow pipe and anti-siphon device and observe the diesel oil can be recirculated from the day tank to the storage tank.

Table 2.16.2c: House Boiler Fuel Oil Storage and Transfer System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the House Boiler Fuel Oil Storage and Transfer System consists of one storage tank anchored to a diked concrete pad located outside the Electrical Building adjacent to the Turbine Building, and includes a transfer pump, piping and controls.	1. Review the as-built House Boiler Fuel Oil Storage and Transfer System documentation and visually inspect the installation to verify the tank, transfer pump, piping and control configuration matches the design documentation.	1. Confirm the as-built House Boiler Fuel Oil Storage and Transfer System installation conforms to the design documentation and confirm the storage tank, pump, piping and controls are located outside the Electrical Building.
2. The fuel oil pump's motor, controls and instrumentation are non-safety and are powered from the plant investment protection electric bus.	2. Review the as-built documentation and visually inspect the installation of the fuel oil pump's motor, controls and instrumentation to verify they are connected to the non-safety plant investment protection electric power bus.	2. Confirm the as-built transfer pump's motor, controls and instrumentation are connected to the plant investment protection electric power bus.
3. The fuel oil pump and associated piping are designed to transfer the fuel oil to the house boiler oil burner at a rate greater than the rate the fuel is consumed by the oil burner at the maximum combustion rate.	3. Review the as-built documentation for the fuel oil pump to determine the flow rate to the house boiler oil burner exceeds the fuel oil consumption of oil burner at the maximum combustion rate.	3. Confirm the as-built fuel oil pump and associated piping are capable of delivering to the house boiler oil burner fuel oil at a rate that exceeds the maximum consumption of the oil burner at the maximum combustion rate.
4. The controls and instrumentation of the House Boiler Fuel Oil Storage and Pumping System are designed to be operable from a local panel in the House Boiler Room.	4. Review the as-built documents and verify by inspection the as-built controls and instruments for the House Boiler Fuel Oil Storage and Pumping System are operable from the House Boiler Room.	4. Confirm the as-built controls and instruments for the House Boiler Fuel Oil Storage and Pumping System are operable from a local panel in the House Boiler Room.

2.16.3 Site Security

Design Description

The ABWR Standard Plant design provides physical security for operating personnel and vital equipment. This is achieved by a combination of plant layout, in plant communications, and emergency lighting.

Plant Layout

All doorways into vital equipment areas will have access monitored by plant security personnel. This is achieved through the use of card reader type door locks for the recording of entry and exit times for all personnel. The location and arrangement of these card based access doors is "Safeguard" information subject to the "Need To Know" provisions of 10 CFR 73 Part 21. Consequently, no details in either the design description or the inspection, test and analyses section are provided in this document.

Emergency Lighting

This item is covered in Section 2.12.18.

In Plant Communication System

This item is covered in Section 2.12.17.

Inspections, Tests, Analyses and Acceptance Criteria

No entries for this system.

3.0 Non-System Based Tier 1 Material

In addition to the system-based Tier 1 material presented in Section 2, separate Tier 1 entries are proposed for subjects not conveniently covered by the system-by-system approach. In general, these non-system Tier 1 entries address subjects that are more generic in nature. That is, they cover technical issues that are relevant to many of the systems addressed in Section 2. An example of a generic technical issue is qualification of safety-related equipment for the environmental conditions that will occur during normal operation and accident conditions. This issue of equipment qualification (EQ) is relevant to many ABWR Systems having a safety function; treatment in a single generic EQ Tier 1 entry avoids repetitious EQ-related entries for multiple systems. Table 3.0 provides a matrix defining the relationship between generic material and the ABWR Systems covered in Section 2.

For selected areas of the ABWR design, there are (for legitimate reasons) insufficient design details available at this time upon which the NRC staff can base a safety finding. Under these circumstances, it has been agreed that the Tier 1 entries for these technical subjects can include some items addressing the detailed design process. For issues in this category, some of the proposed inspections, tests, analyses and acceptance criteria (ITAAC) will be aimed at verifying implementation of the design process, i.e., will utilize design acceptance criteria (DAC). The remaining ITAAC entries will still focus on confirming the as-built facility is in compliance with the certified design. Reference 1 contains a more detailed discussion of the DAC concept and the criteria which will be used to govern application of the concept. ABWR technical issues which will have elements of a design acceptance approach in their Tier 1 treatment are:

(1) Instrumentation and control design issues including Human Factors Engineering (HFE)

(2) Radiation protection

(3) Piping

In summary, this section provides Tier 1 material that is generic in nature and is more efficiently handled outside the system-by-system approach being used for the bulk of the ABWR Tier 1 material. Furthermore, to the extent that it is being used for the ABWR design certification, this section also includes material that will achieve design verification utilizing the DAC process.

Table 3.0: Applicability of Generic Material to ABWR Systems

ABWR System	3.1 Equipment Qualification	3.2 Instrument Setpoint Methods	3.3 Piping Design	3.4 Safety System Logic and Control	3.5 Software Development	3.6 Human Factors Engineering	3.7 Radiation Protection	3.8 Reliability Maintenance Program	3.9 Welding
2.1.1 Reactor Pressure Vessel System									X
2.1.2 Nuclear Boiler System	X	X	X	X	X				X
2.1.3 Reactor Recirculation System			X						X
2.2.1 Rod Control and Information System									
2.2.2 Control Rod Drive System	X	X	X						X
2.2.3 Feedwater Control System									X
2.2.4 Standby Liquid Control System	X	X	X						X
2.2.5 Neutron Monitoring System	X	X		X	X				
2.2.6 Remote Shutdown System	X								
2.2.7 Reactor Protection System	X	X		X	X				
2.2.8 Recirculation Flow Control System									
2.2.9 Automatic Power Regulator System									
2.2.10 Steam Bypass and Pressure Control System									
2.2.11 Process Computer									
2.2.12 Refueling Platform Control Computer									

Table 3.0: Applicability of Generic Material to ABWR Systems

ABWR System	3.1 Equipment Qualification	3.2 Instrument Setpoint Methods	3.3 Piping Design	3.4 Safety System Logic and Contr	3.5 Software Development	3.6 Human Factors Engineering	3.7 Radiation Protection	3.8 Reliability Maintenance Program	3.9 Welding
2.2.13 CRD Removal Machine Control Computer									
2.3.1 Process Radiation Monitoring System	X	X	X	X	X	X			X
2.3.2 Area Radiation Monitoring System	X	X				X			
2.3.3 Containment Atmospheric Monitoring System	X						X		
2.4.1 Residual Heat Removal System	X	X	X	X	X				X
2.4.2 High Pressure Core Flooder (HPCF) System	X	X	X	X	X				X
2.4.3 Leak Detection and Isolation System	X	X		X	X				
2.4.4 Reactor Core Isolation Cooling System	X	X	X	X	X				X
2.5.1 Fuel Servicing Equipment									
2.5.2 Miscellaneous Servicing Equipment									
2.5.3 Reactor Pressure Vessel Servicing Equipment									
2.5.4 RPV Internal Servicing Equipment									
2.5.5 Refueling Equipmen									
2.5.6 Fuel Storage Facility									

Table 3.0: Applicability of Generic Material to ABWR Systems

ABWR System	3.1 Equipment Qualification	3.2 Instrument Setpoint Methods	3.3 Piping Design	3.4 Safety System Logic and Control	3.5 Software Development	3.6 Human Factors Engineering	3.7 Radiation Protection	3.8 Reliability Maintenance Program	3.9 Welding
2.5.7 Undervessel Servicing Equipment									
2.5.8 CRD Maintenance Facility									
2.5.9 Internal Pump Maintenance Facility									
2.5.10 Fuel Cask Cleaning Facility									
2.5.11 Plant Start-up Test Equipment									
2.5.12 Inservice Inspection Equipment									
2.6.1 Reactor Water Cleanup System	X		X						X
2.6.2 Fuel Pool Cooling and Cleanup System	X		X						X
2.6.3 Suppression Pool Cleanup System			X						X
2.7.1 Main Control Room Panel	X					X			
2.7.2 Radioactive Waste Control Panel									
2.7.3 Local Control Panels	X								
2.7.4 Instrument Racks	X								
2.7.5 Multiplexing System	X	X		X	X				
2.7.6 Local Control Box	X								
2.8.1 Nuclear Fuel and LPMS									
2.8.2 Fuel Channel									
2.8.3 Control Rod									

Table 3.0: Applicability of Generic Material to ABWR Systems

ABWR System	3.1 Equipment Qualification	3.2 Instrument Setpoint Methods	3.3 Piping Design	3.4 Safety System Logic and Control	3.5 Software Development	3.6 Human Factors Engineering	3.7 Radiation Protection	3.8 Reliability Maintenance Program	3.9 Welding
2.9.1 Radwaste System									X
2.10.1 Turbine Main Steam System									X
2.10.2 Condensate Feedwater and Condensate Air Extraction System									X
2.10.3 Heater Drain and Vent System									
2.10.4 Condensate Purification System									
2.10.5 Condensate Filter Facility									
2.10.6 Condensate Demineralize									
2.10.7 Turbine									X
2.10.8 Turbine Control System									
2.10.9 Turbine Gland Steam System									
2.10.10 Turbine Lubricating Oil System									
2.10.11 Moisture Separator Heater									X
2.10.12 Extraction System									X
2.10.13 Turbine Bypass System									X
2.10.14 Feedwater Pump Driver									
2.10.15 Turbine Auxiliary Steam System									

Table 3.0: Applicability of Generic Material to ABWR Systems

ABWR System	3.1 Equipment Qualification	3.2 Instrument Setpoint Methods	3.3 Piping Design	3.4 Safety System Logic and Control	3.5 Software Development	3.6 Human Factors Engineering	3.7 Radiation Protection	3.8 Reliability Maintenance Program	3.9 Welding
2.10.16 Generator									
2.10.17 Hydrogen Gas Cooling System									
2.10.18 Generator Cooling System									
2.10.19 Generator Sealing Oil System									
2.10.20 Exciter									
2.10.21 Main Condenser									X
2.10.22 Off-Gas System									X
2.10.22 Circulating Water System									X
2.10.23 Condenser Cleanup Facility									X
2.11.1 Makeup Water System (Purified									X
2.11.2 Makeup Water System (Condensate)									X
2.11.3 Reactor Building Cooling Water System	X		X						X
2.11.4 Turbine Building Cooling Water System									X
2.11.5 HVAC Normal Cooling Water System									X
2.11.6 HVAC Emergency Cooling Water System	X	X	X						X

Table 3.0: Applicability of Generic Material to ABWR Systems

ABWR System	3.1 Equipment Qualification	3.2 Instrument Setpoint Methods	3.3 Piping Design	3.4 Safety System Logic and Control	3.5 Software Development	3.6 Human Factors Engineering	3.7 Radiation Protection	3.8 Reliability Maintenance Program	3.9 Welding
2.11.7 Oxygen Injection System									
2.11.8 Ultimate Heat Sink	X								X
2.11.9 Reactor Service Water System	X		X						X
2.11.10 Turbine Service Water System									X
2.11.11 Station Service Air System									X
2.11.12 Instrument Air System									X
2.11.13 High Pressure Nitrogen Gas Supply System	X	X	X						X
2.11.14 Heating Steam and Condensate Water Return System									X
2.11.15 House Boiler									
2.11.16 Hot Water Heating System									X
2.11.17 Hydrogen Water Chemistry System							X		X
2.11.18 Zinc Injection System									X
2.11.19 Breathing Air System							X		
2.11.20 Process Sampling System									
2.11.21 Freeze Protection System									
2.11.22 Iron Injection System									

Table 3.0. Applicability of Generic Material to ABWR Systems

ABWR System	3.1 Equipment Qualification	3.2 Instrument Setpoint Methods	3.3 Piping Design	3.4 Safety System Logic and Control	3.5 Software Development	3.6 Human Factors Engineering	3.7 Radiation Protection	3.8 Reliability Maintenance Program	3.9 Weldir
2.12.1 Electrical Power Distribution System	X								
2.12.2 Unit Auxiliary Transformer									
2.12.3 Isolated Phase Bus									
2.12.4 Nonsegregated Phase Bus	X								
2.12.5 Metal Clad Switchgear	X	X							
2.12.6 Power Center	X	X							
2.12.7 Motor Control Center	X	X							
2.12.8 Raceway System	X								
2.12.9 Grounding Wire	X								
2.12.10 Electrical Wiring Penetration	X								
2.12.11 Combustion Turbine Generator									X
2.12.12 Direct Current Power Supply	X	X							
2.12.13 Emergency Diesel Generator System (Standby AC Power Supply)	X	X							X
2.12.14 Reactor Protection System Alternate Current Power Supply	X	X							
2.12.15 AC Power Supply And AC Instrument and Control Power Supply Systems	X	X							

Table 3.0: Applicability of Generic Mate.ial to ABWR Systems

ABWR System	3.1 Equipment Qualification	3.2 Instrument Setpoint Methods	3.3 Piping Design	3.4 Safety System Logic and Control	3.5 Software Development	3.6 Human Factors Engineering	3.7 Radiation Protection	3.8 Reliability Maintenance Program	3.9 Welding
2.12.16 Instrument and Control Power Supply	X	X							
2.12.17 Communication System									
2.12.18 Lighting and Service Power Systems	X								
2.13.1 Reserve Auxiliary Transformer									
2.14.1 Primary Containment System	X						X		X
2.14.2 Containment Internal Structures									X
2.14.3 Reactor Pressure Vessel Pedestal									X
2.14.4 Standby Gas Treatment System	X	X	X						X
2.14.5 PCV Pressure and Leak Testing Facility									
2.14.6 Atmospheric Control System	X	X							
2.14.7 Drywell Cooling System									X
2.14.8 Flammability Control System	X	X							X
2.14.9 Suppression Pool Temperature Monitoring System	X	X							
2.15.1 Foundation Work									
2.15.2 Turbine Pedestal									X
2.15.3 Cranes and Hoists									X

Table 3.0: Applicability of Generic Material to ABWR Systems

ABWR System	3.1 Equipment Qualification	3.2 Instrument Setpoint Methods	3.3 Piping Design	3.4 Safety System Logic and Control	3.5 Softw re Development	3.6 Human Factors Engineering	3.7 Radiation Protection	3.8 Reliability Maintenance Program	3.9 Welding
2.15.4 Elevator									X
2.15.5 Heating, Ventilating and Air Conditioning							X		X
2.15.6 Fire Protection System									X
2.15.7 Floor Leakage Detection System									
2.15.8 Vacuum Sweep System									
2.15.9 Decontamination System									
2.15.10 Reactor Building							X		X
2.15.11 Turbine Building							X		X
2.15.12 Control Building							X		X
2.15.13 Radwaste Building							X		X
2.15.14 Service Building							X		X
2.16.1 Stack									X
2.16.2 Oil Storage and Transfer System									
2.16.3 Site Security									

3.1 Equipment Qualification (EQ)

Design Description

Mechanical and electrical equipment that is important to safety is qualified for the full range of environmental conditions that will exist up to and including the time the equipment has finished performing its safety-related function. Equipment used for the certified design will be in full compliance with the regulatory requirements and industrial standards governing qualification methodology to be used for safety equipment in nuclear power plants.

The scope of this generic material is to address the complete spectrum of environmental conditions that may occur in the facility. Not all safety equipment will experience all of these conditions; the intent is that qualification be performed by selecting the conditions applicable to each particular piece of equipment and performing the necessary qualification using acceptable methods.

Inspections, Tests, Analyses and Acceptance Criteria

Table 3.1 provides a definition of the inspections, tests, and/or analyses (together with associated acceptance criteria) which will be performed to demonstrate compliance with the equipment qualification commitments for the certified design.

Table 3.1: Equipment Qualification

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Mechanical and electrical equipment important to safety will be qualified for the environmental conditions that exist up to and including the time the equipment has finished performing its safety- related function. Conditions that exist during normal, abnormal and design basis accident events will be considered in terms of their cumulative effect on equipment performance. These conditions will be considered for the time period up to the end of components refurbishment interval or end of equipment life. These conditions include number and/or duration of equipment functional and test cycles/ events; process fluid conditions (where applicable); the voltage, frequency, load, and other electrical characteristics of the equipment; the dynamic loads associated with seismic events, containment response to hydrodynamic conditions, system transients, and other vibration inducing events, and the pressure, temperature, humidity, chemical and radiation environments, aging and submergence (if any) that can affect or degrade equipment performance. Other environmental conditions that will be considered are those included within environmental compatibility (EMC). These conditions are electromagnetic interference (EMI), electrostatic discharge (ESD), radio-frequency interference (RFI) and surge withstand capability (SWC).	1. Documentation relating to EQ issues will be completed for all equipment items important to safety and reviewed on a selected basis for compliance with requirements. This documentation will be in the form of the equipment qualification list and the device specific qualification files. The review will include review of specified environmental conditions, qualification methods (e.g., analyses or testing), and documentation of qualification results.	1. It will be confirmed that a comprehensive list of equipment important to safety has been prepared. The following information for this equipment shall be provided in a qualification file and subject to audit: a. The performance specifications under conditions existing during and following design basis accidents. For electrical items, this will include the voltage, frequency, load and other electrical characteristics for which the performance specified above can be ensured. b. The environmental conditions, including temperature, pressure, humidity, radiation, electromagnetic compatibility, chemicals and submergence at the location where the equipment must perform as specified above. This will include environmental conditions defined in 10 CFR 50.49, for electrical items and shall include consideration of synergistic effects and margins for unquantified uncertainty. c. The testing method used to qualify the equipment. Each item of equipment important to safety must be qualified by one (or a combination) of the following methods: (1) Testing an identical item of equipment under identical conditions or under similar conditions with a

Table 3.1: Equipment Qualification (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
		1.c (continued) supporting analysis to show that the equipment to be qualified is acceptable. 2) Testing a similar item of equipment with a supporting analysis to show that the equipment to be qualified is acceptable. 3) Experience with identical or similar equipment under similar conditions with a supporting analysis to show that the equipment to be qualified is acceptable. 4) Analysis in combination with partial type test data that supports the analytical assumptions and conclusions. e. The results of the qualification have been documented to permit verification that the item of equipment important to safety: 1) Is qualified for its application; and 2) Meets its specified performance requirements when it is subjected to the conditions predicted to be present when it must perform its safety function up to the end of its qualified life.

Table 3.1: Equipment Qualification (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
2. The installed condition of mechanical and electrical equipment important to safety will be compatible with conditions for which it was qualified.	2. An inspection will be performed of installed safety equipment to assess compatibility with the methods and assumptions used to qualify the equipment.	2. The installed configuration is bounded by the test configuration and conditions. No physical interferences exist with adjacent plant feature which have not been addressed by the qualification process.

3.2 Instrument Setpoint Methodology

Design Description

A disciplined approach is use when establishing allowable values and nominal trip setpoints for instruments having safety-related trip functions. The following is a generic treatment of the processes which will be used to verify that this is accomplished. Definition of detailed procedures and development of specific setpoints is dependent upon as-built, as-procured instrumentation characteristics and is not addressed as part of design certification.

The determination of nominal trip setpoints (NTSP)[1] must include a consideration of many factors. In the case of setpoints which are directly associated with an abnormal plant transient or accident analyzed in the safety analysis, a design basis analytical limit is established as part of the safety analysis. The design basis analytical limit is the value of the sensed process variable prior to or at the point where a desired action is to be initiated. The design basis analytical limit is set so that appropriate licensing safety limits (LSL) are not exceeded, as confirmed by plant design basis performance analysis. An allowable value[2] is determined from the analytical limit by providing allowances for the specified or expected calibration capability and accuracy of the instrumentation and the measurement errors. The nominal trip setpoint value is calculated from the analytical limit by taking into account instrument drift in addition to the instrument accuracy, calibration and the measurement errors.

Not all parameters have an associated design basis analytical limit (e.g., main steam line radiation monitoring). An allowable value may be defined directly based on plant licensing requirements, previous operating experience or other appropriate criteria. The nominal trip setpoint is then calculated from this allowable value, allowing for instrument drift. Where appropriate, a nominal trip setpoint may be determined directly based on operating experience.

Procedures will be used that provide a consistent and repeatable method for establishing instrument nominal trip setpoint and allowable value. Because of the general characteristics of the instrumentation and processes involved, three different methods are used:

(1) Computational

(2) Historical Data

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(1) The limiting value of the sensed process variable at which a trip action will be set to operate at the time of calibration.

(2) The limiting value of the sensed process variable at which the trip setpoint may be found during instrument surveillance

The intent of the detailed procedures is to assure that installed instrumentation meets Instrument Society of America (ISA) and NRC approved regulatory requirements applicable to nuclear power plant instruments.

Inspections, Tests, Analyses and Acceptance Criteria

Table 3.2 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken to assure detailed procedures are defined and implemented for establishing instrument setpoints in a structured, disciplined manner.

Table 3.2: Instrument Setpoint Methodology

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Detailed procedures will be established and utilized for development of instrument setpoints using approved methodology. These procedures will be utilized for all plant instrumentation but will recognize and allow for different approaches for the different classes of instrumentation.	1. Instrument setpoint acitvities conducted prior to fuel load will be reviewed for compliance.	1. Detailed procedures are in place and are being used for all setpoint activitites. The procedures are based on approved methodology.
2. All instrument setpoint related activities will be documented and stored in retrievable, auditable files.	2. Document retention practices will be reviewed for compliance with the commitment.	2. Retrievable, auditable files are inplace for all instrument setpoint related activities.

3.3 Piping Design

Design Description

Piping associated with hydraulic and pneumatic systems is categorized as either nuclear safety related or non-safety related. Piping systems that must remain functional following a safe shutdown earthquake (SSE) are designated as Seismic Category I. Depending on the intended service conditions and system design functions, piping is further classified as ASME Code Class 1, 2, 3, or non-Code Class. NRC regulations govern piping designations and piping in the certified design may further be classified as Quality Group A, B, C, or D.

All ABWR piping components will be designed, fabricated, installed and examined to confirm full compliance with all applicable regulatory requirements and industrial codes and standards.

Inspections, Tests, Analyses and Acceptance Criteria

Table 3.3 provides a definition of the inspections, tests and analyses, together with the acceptance criteria, which will be performed for ABWR piping in order to demonstrate compliance with the certified design commitments. The information in Table 3.3 is intended to be generic and to apply to all safety related piping governed by Quality Group A, B, or C and ASME Code Class 1, 2, or 3 designations. Not all of the entries in Table 3.3 apply to all piping classifications. Appropriate applicability, based on designation, will be incorporated at the time the inspections, tests, and analyses are implemented.

Table 3.3: Generic Piping Design

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
Design items:		
1. The piping shall be designed for a fatigue life of 60 years. This design shall account for the cyclic stresses resulting from the expected pressure/temperature cycles and loads in the required combinations. For ASME Class 1 piping systems, a fatigue analysis will be performed in accordance with ASME Code, Section III requirements. In the fatigue evaluation, the environmental effects shall be considered. For ASME Class 2 & 3 piping, ASME Code, Section III rules will be followed using a code-prescribed stress range reduction factor corresponding to the design basis number of cycles. These fatigue analyses results shall be documented in a certified stress report.	1. An inspection of the certified stress report will be conducted to assure that the fatigue evaluation is consistent with the ASME Code, Section III requirements and with the 60 year design life.	1. ASME Code, Section III requirements shall be satisfied, including the cumulative fatigue usage factor, which shall be less than or equal to [illegible]. The applied subsections of ASME Code shall be contained in the approved editions documented in 10CFR50.55a.

Table 3.3: Generic Piping Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
2. Pipe mounted equipment allowable loads and attachment interface (for example, the interface between a snubber and its embedment plate) allowable loads, accelerations and stresses shall be satisfied. The loads, accelerations, and stresses that the piping system imposes on its pipe mounted equipment and on its interfaces shall be determined by analyses of the piping systems and compared to the allowable values. The results of these analyses shall be documented as interface requirements to assure design compatibility with the equipment and interfaces.	2. Inspections of stress reports, design specifications, and design drawings will be conducted to confirm that the as-designed interface loads, accelerations and stresses are consistent with the interfacing vendor's / constructor's specified hardware allowables.	2. The allowables for pipe mounted equipment and interfacing equipment shall be met. The allowables at attachment interfaces shall be met.

Table 3.3: Generic Piping Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3. Analytical methods for the dynamic and static analysis of piping systems and the corresponding component stress analysis shall be specified in a certified design specification for each piping system. The analytical methods used shall ensure the pressure integrity, structural integrity, and the functional capability of the piping system under normal operating, transient, and accident loading conditions. The dynamic analysis of piping systems shall use a suitable dynamic method, such as time history or response spectrum method, or an equivalent static load method. Linear-elastic analysis or nonlinear-plastic analysis shall be used. For the applied method, the key analysis parameters shall be addressed. For example, for the response spectrum method, the following shall be defined: a. Combination of group responses when multiple response spectra are used. b. Combination of modal responses. c. Combination of response spectra analysis results with differential building movement analysis results. d. Damping coefficients. e. Cut-off frequency. f. High frequency modes.	3. Inspection (review) of the certified design specification and the certified stress report will be conducted to confirm that the piping was designed and analyzed in compliance with all regulatory (and other applicable) requirements.	3. Methods shall be in compliance with all applicable regulatory requirements.

Table 3.3: Generic Piping Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4. Essential piping systems, including required pipe whip restraints, shall be designed to protect against the dynamic effects associated with the postulated rupture of high energy and moderate energy fluid systems. A pipe break analysis report shall be generated to confirm that the piping system is acceptable for all postulated breaks. A pipe rupture analysis to confirm that safety-related systems, structures, and components are protected against the dynamic effects of a postulated pipe break shall be completed using the NRC approved methods. Piping systems that are qualified for the optional leak-before-break design approach may exclude design against the dynamic effects from the postulation of breaks in high energy piping.	4. Inspections of ASME Code III required documents, the pipe break analysis report, and the pipe rupture analysis report, or leak-before-break justification report, will be conducted to confirm that the piping system was designed/analyzed in compliance with requirements that assure postulated pipe breaks will not unduly impact the safety of the plant.	4. The essential functions of structures, systems, and components shall not be precluded by the postulated pipe breaks. For those components required for safe shutdown, limits to meet the ASME Code requirements for faulted conditions and limits to ensure required operability shall be met.
5. All ASME Code Safety Class 1, 2, and 3 piping systems which are essential for safe shutdown, shall be designed to assure that they will maintain sufficient dimensional stability to perform their required function following application of all loads to which they will be subjected during postulated events requiring their safety function.	5. An inspection of the certified stress report will be conducted to assure that none of the stresses or deflections of the piping system exceed values which could lead to large reductions in the cross-sectional flow area.	5. ASME Code, Section III limits that protect the piping and pipe supports against primary stress failures will be compared with allowable values that preclude impairment of functional capability. In no case will stresses exceed values allowed for Service Level D in ASME Code, Section III.

Table 3.3: Generic Piping Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. When performing static and dynamic analysis of piping systems, the mathematical model of the piping system shall be constructed to realistically reflect the dynamic and static characteristics of the piping system. The following parameters shall be addressed: The model shall adequately account for modes up to the analysis cut-off frequency. a. The appropriate stiffness and mass of piping, pipe supports, and pipe mounted equipment shall be included in the piping system model. a. The appropriate stiffnesses for anchors and intermediate supports shall be included in the piping system model.	6. An inspection (verification) of the mathematical model will be performed to confirm that the boundary conditions and dynamic and static characteristics have been adequately technically addressed.	6. Analytical modeling practices shall be in compliance with all applicable regulatory requirements. The methods used for modeling will be applied to NRC benchmark problems and the results of the corresponding analyses shall be compared to the NRC benchmark and consistency shall be confirmed.
Construction Items:		
7. The piping, its appurtenances, and its supports, shall satisfy the ASME Class, Seismic Category, and Quality Group requirements commensurate with its classification.	7. Inspections will be conducted of ASME Code required documents and the Code stamp on the components.	7. Existence of ASME Code required documents and the Code stamps on the components confirms that the piping and components have been designed, analyzed, fabricated, and examined in accordance with the applicable requirements.

Table 3.3: Generic Piping Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8. For those piping systems using ferritic materials, the ferritic materials shall not be susceptible to brittle fracture under pressure during the expected service conditions. Only intrinsically tough grades of ferritic materials conforming to the ASME Code, Section III SA specifications shall be used.	8. Fracture toughness tests will be performed in accordance with ASME Code, Section III.	8. Records of the fracture toughness tests must confirm that the requirements of ASME Code, Section III are satisfied.
9. For those piping systems using austenitic stainless steel materials, the stainless steel piping shall be selected to minimize the possibility of cracking during service. Special chemical, fabrication, handling, welding, and examination requirements that minimize cracking shall be met.	9. Inspections of ASME Code required documents and other pertinent records will be conducted to confirm that manufacture, fabrication, welding, and examination were performed in accordance with the committed requirements.	9. Records of the materials and processes must confirm that the committed requirements to avoid the potential of stainless steel to crack in service are satisfied.

Table 3.3: Generic Piping Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
10. For essential systems, the as-built piping system shall be confirmed to be consistent with the as-designed piping system. All deviations shall be shown to not invalidate the design.	10.	10.
	a. Pipe routing will be confirmed by inspecting isometric drawings containing verification stamps from field visual inspections. This documentation will also confirm that no interferences exist	a. The as-built pipe routing is within the tolerances allowed on the as-designed drawings. The piping system has the minimum specified clearance from neighboring hardware. Deviations shall be addressed in compliance with c below.
	a. The exact location, orientation, and size of snubbers and struts; the location and size of hangers; the location and weight of valves, pumps, and heat exchangers; the location and configuration of anchors; the location of guides and pipe whip restraints; and the specified clearances, will be confirmed by reviewing isometric drawings containing quality control verification stamps, or by taking the as-built measurements.	a. The location, size, orientation of pipe mounted components are within the tolerances allowed on the as-designed drawings. Deviations shall be addressed in compliance with c below.
	a. Deviations from the as-designed condition will be documented and evaluated. If acceptance limits are not satisfied in the reevaluation, a reanalysis of the as-built condition will be performed to confirm that all stress limits and interface load requirements have been met. The stress report and	a. For Safety Class 1, 2, & 3 piping, the required allowables in the applicable subsections of ASME Code, Section III shall be satisfied. The applied subsections of ASME Code, Section III shall be contained in the approved editions documented in 10 CFR 50.55a. The ASME Code, Section III allowables for pipe mounted equipment and interfacing equipment shall be met. The ASME Code, Section III allowables at attachment interfaces shall be met.

Table 3.3: Generic Piping Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
Combination Design and Construction Items:		
11. ASME Code Safety Class 1, 2, and 3 piping shall retain its pressure integrity under all internal pressures that will be expected during its design lifetime. Piping and piping components sh·'l be designed and analyzed to show compliance with the pressure integrity requirements of ASME Code.	11. a. Inspections of ASME Code required documents will be conducted to confirm that the piping system was designed/analyzed in compliance with requirements that assure pressure integrity. a. A hydrostatic test of the Safety Class 1, 2, and 3 piping will be conducted as required by, and in accordance with, the ASME Code.	11. a. For safety class 1, 2, & 3 piping, the required allowables in the applicable subsections of ASME Code, Section III shall be satisfied. The applied subsections of ASME Code, Section III shall be contained in the approved editions documented in 10 CFR 50.55a. a. The results of the hydrostatic test must conform with the requirements in the ASME Code.
12. Piping shall be designed (and installed) to provide adequate clearance to prevent interference with other piping, structures, and components as the piping moves or deflects due to the thermal, dynamic, and/or static loads which it experiences in service. Stress analyses shall be performed to calculate piping movements. These calculated movements shall be used to develop and document minimum required clearances.	12. a. An inspection of the certified stress report will be conducted to assure that the calculated pipe deflection values do not result in the piping exceeding its design allowables for the specified load combinations and that the minimum specified clearances adequately encompass these deflections. a. A field walkdown will be performed on all essential piping to measure the "As-installed" piping clearances and confirm the actual clearances are within allowable values.	12. The design allowables for piping clearance in both the axial and lateral directions shall be met.

3.4 Safety System Logic and Control

Design Description

Safety System Logic and Control (SSLC) integrates the automatic and manual decision-making and trip logic functions associated with the safety actions of the safety-related systems of the Composite Nuclear Plant System (CNPS). These safety-related systems, taken together, include all the hardware and circuitry, from sensor to actuation device input terminals, that generate signals associated with plant protection. The protective function signals are those that activate reactor trip and those that provide essential mitigation of consequences of reactor accidents to assure the required protection of the general public and the plant. The relationship between SSLC and systems for plant protection is shown in Figure 3.4a.

System redundancy is provided by four physical and electrical divisional separations. Each independent division correlates protective action for reactor trip, containment isolation, and emergency core cooling inputs and outputs (emergency core cooling outputs are located in three divisions). Separate divisions are established by their physical relationship to the reactor vessel, which is divided into four quadrants. The sensors, logic, and output actuators of the various systems are allocated to these divisions.

SSLC equipment comprises microprocessor-based, software-controlled, signal processors that perform signal conditioning, setpoint comparison, trip logic, self-test, calibration, and bypass functions. The signal processors associated with a particular CNPS system are an integral part of that system and their functions are included as part of that system's documentation. Functions in common, such as self-test, calibration, bypass control, power supplies and certain switches and indicators, belong to SSLC, although SSLC is not by itself a CNPS system. SSLC is an assemblage of several safety-related system's signal processors designed and grouped for optimum reliability, availability, and maintainability. SSLC hardware and software is classified as safety-related, Class 1E, and is seismically qualified.

Sensors used by the safety-related systems can be either analog, such as process control transmitters, or discrete, such as limit switches and other contact closures. Most sensor signals are transmitted from the instrument racks in the Reactor Building to the SSLC equipment in the Control Building via the Essential Multiplexing System (EMS). Divisional separation is also applied to EMS. Both analog and discrete sensors are connected to Remote Multiplexing Units (RMUs) in local areas, which perform signal conditioning, analog-to-digital conversion for continuous process inputs, change-of-state detection for discrete inputs, and message formatting prior to signal transmission. The RMUs are limited to acquisition of sensor data and the output of control signals. Trip decisions and other control logic functions are performed in SSLC processors in the main control room area.

SSLC Signal Processing

The basic hardware configuration of one division of SSLC is shown in Figure 3.4b. Each division runs continuously and independently (i.e., asynchronously) with respect to the other divisions. The following steps describe the processing sequence for incoming sensor signals and outgoing control signals. These steps are performed simultaneously and independently in each of the four divisions:

(1) The digitized sensor inputs received in the control room are decoded by a microprocessor-based function, the Digital Trip Module (DTM). For each system function, the DTM compares these inputs to the preprogrammed levels (setpoints) for possible trip action.

(2) For Reactor Protection System (RPS) trip and Main Steam Isolation Valve (MSIV) closure functions, trip outputs from the DTM are then compared, using a 2-out-of-4 coincident logic format, with trip outputs from the DTMs of the other three divisions. The trip outputs are compared in the Trip Logic Unit (TLU), another microprocessor-based device. The logic format for the DTM and TLU is fail-safe (i.e., de-energize-to-operate). Thus, a reactor trip or MSIV closure output occurs on loss of signal or power to the DTM, but, because of the 2-out-of-4 logic format in the TLU, a trip state does not appear at the output of the TLU. Loss of signal or power to a TLU also causes a trip state, but the 2-out-of-4 configuration of actuator load drivers prevents actual de-energization of the pilot valve solenoids.

Trips are transmitted across divisions for 2-out-of-4 voting via fiber optic data links to preserve signal isolation among divisions. The TLU also receives inputs directly from the trip outputs of the Neutron Monitoring System, manual control switch inputs, and contact closures from limit switches and position switches used for equipment interlocks. In addition, plant sensor signals and contact closures that do not require transmittal to other divisions for 2-out-of-4 trip comparison are provided as inputs directly to the TLU. The TLU performs the trip setpoint comparison function as required.

(3) For Leak Detection and Isolation System (LDS) functions (except MSIV), ECCS functions, and auxiliary ESF functions, logic processing is performed as above, but in separate DTMs and Safety System Logic Units (SLUs). The SLUs are similar to TLUs, but are dual redundant in each processing channel for protection against inadvertent initiation. Dual SLUs both receive the same inputs from the DTM, manual control

switch inputs, and contact closures. Both SLU outputs must agree before the final trip actuators are energized. In general, the logic format for the DTM and SLUs is fail-as-is (i.e., energize-to-operate). Loss of power or equipment failure will not cause a trip or initiation action. An exception is the containment isolation signals, which are in fail-safe format. Besides the 2-out-of-4 voting logic, the SLUs also perform interlock logic functions for each supported safety system. This logic ensures that safety system equipment is in a correct configuration for any required mode of operation.

(4) For reactor trip or MSIV closure, if a 2-out-of-4 trip condition is satisfied, all four divisions' trip outputs will produce a simultaneous coincident trip signal (for example, reactor trip) and transmit the signal via isolators and load drivers to the actuators for protective action. The load drivers are themselves arranged in a 2-out-of-4 configuration, so that at least two divisions must produce trip outputs for protective action to occur. For ESF functions, the trip signals in three divisions are transmitted via the Essential Multiplexing System to the Remote Multiplexing Units, where a final 2-out-of-2 logic comparison is made prior to distribution of the control signals to the final actuators. ESF outputs do not exist in Division IV.

(5) Upon loss of AC or DC power, functions which are normally energized, such as reactor trip or MSIV closure, provide fail-safe trip action. For normally-de-energized functions, such as ECCS, power failures leave the state of the actuated equipment unchanged. Subsequent restoration of power will not introduce transients that could cause an inadvertent change of state in the actuated equipment.

Division-of-sensors Bypass

Bypassing of any single division of sensors (i.e., those sensors whose trip status is confirmed by 2-out-of-4 logic) is accomplished from each divisional SSLC cabinet by means of the manually-operated Bypass Unit. When such bypass is made, all four divisions of 2-out-of-4 input logic become 2-out-of-3 while the bypass state is maintained. Bypass permits calibration and repair of sensors or the DTM without danger of inadvertent trip action. During bypass, if any two of the remaining three divisions reach trip level for any sensed input parameter, then the output logic of all four divisions will trip (for RPS and MSIV functions) or the three ECCS divisions will initiate the appropriate safety system equipment.

Bypass status is indicated to the operator until the bypass condition is removed. An electrical interlock will reject attempts to bypass more than one SSLC division at a time.

Division-out-of-service Bypass

Bypassing of any single division of output trip logic (i.e., taking a logic channel out of service) is also accomplished by means of the Bypass Unit. This type of bypass is limited to the fail-safe (de-energize-to-operate) reactor trip and MSIV closure functions, since removal of power from energize-to-operate signal processors is sufficient to remove that channel from service.

When a division-out-of-service bypass is made, the TLU trip output in a division is inhibited from affecting the output load drivers by maintaining that division's load drivers in an energized state. Thus, the 2-out-of-4 logic arrangement of output load drivers for the RPS and MSIV functions effectively becomes 2-out-of-3 while the bypass is maintained. Maintenance or repair of signal processing equipment or extensive off-line testing can be accomplished within the bypassed division without danger of trip action.

Bypass status is indicated to the operator until the bypass condition is removed. An electrical interlock will reject attempts to remove more than one SSLC division from service at a time.

Testability

A hierarchy of test features is provided to ensure maximum coverage of all SSLC logic functions and data communications links. Test capability includes:

(1) Internal, automatic, on-line self-test of each signal processing module from input to output. This test does not affect trip outputs.

(2) Manually-initiated off-line self-test that toggles all trip outputs.

(3) Passive monitoring of power supply voltages and equipment interlocks.

(4) A surveillance test control unit to perform off-line, semi-automatic, simulation testing of SSLC functional logic, including trip, initiation, and interlock logic.

Inspections, Tests, Analyses and Acceptance Criteria

Table 3.4 provides a definition of the visual inspections, tests and analyses, together with associated acceptance criteria, which will be used by SSLC.

Table 3.4: Safety System Logic And Control

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Four divisions of independent and redundant instrumentation process the safety-related sensor inputs and control logic functions of the plant standby safety systems and auxiliary supporting systems.	1. Visual inspection of the installed equipment will confirm the identity and location of SSLC instrumentation, equipment panels, and their interconnections.	1. The system configuration, including interfacing plant systems, is in accordance with Figures 3.4c, 3.4d and 3.4e.
2. SSLC panels and processing equipment are Class 1E, safety-related, and seismically qualified.	2. Visual inspection of installed equipment, test records, and analyses based on equipment location will confirm the qualification status of SSLC.	2. Installed configuration of SSLC conforms to certified commitment.
3. The four divisions of redundant instrumentation are physically and electrically separated from each other. Any required interconnections among divisions, such as data communications among divisions for coincident trip logic decisions, shall use an isolating transmission medium such as fiber optic cables. Any required outputs to non-safety-related systems will also use an isolating transmission medium.	3. Inspections of fabrication and installation records and construction drawings or visual field inspections of the installed SSLC equipment will be used to confirm electrical and physical separation.	3. The installed SSLC equipment conforms to certified commitment.
4. The DTM, TLU, and OLUs for RPS/MSIV in each instrumentation division are powered from the divisional Vital AC sources (Class 1E 120 V UPS). The DTMs and SLUs for ESF 1 and ESF 2 in Div. 1, 2, and 3 are powered from the divisional plant DC sources (Class 1E 125 VDC, Div. 1, 2, 3)	4. System tests will be conducted after installation to confirm that the electrical power supply configurations are in compliance with design commitments.	4. The installed instrument channels are operational with the power sources specified in the certified commitment.

Table 3.4: Safety System Logic And Control (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. SSLC meets Electromagnetic Compatibility (EMC) requirements. Protection is provided against the effects of: a. Electromagnetic Interference (EMI) b. Radio Frequency Interference (RFI) c. Electrostatic Discharge (ESD) d. Electrical surge [Surge Withstand Capability (SWC)]	5. Factory tests for EMC will be conducted in a controlled environment on individual SSLC equipment and on the integrated system configuration. EMC tests will also be conducted on the installed SSLC configuration in the normal plant operating environment.	5. EMC performance of SSLC is considered acceptable if tests confirm that electromagnetic fields, static discharges, and electrical surges do not affect system capability to trip on demand, avoid inadvertent trip, operate in bypassed condition, and perform self-test functions.

Table 3.4: Safety System Logic And Control (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. SSLC operability is demonstrated by means of manually-initiated in-service test features. These features are provided for on-line repair, maintenance, and surveillance testing, and for support of the test modes of each safety system. Supported tests are: a. Setpoint validation b. RPS and MSIV trip logic test of TLU c. Divisional RPS trip test d. MSIV closure test (individual) e. Manual isolation test (all MSIVs) f. MSIV test closure g. Trip logic test of SLU h. Safety system equipment operation (pump and valve testing).	6. Preoperational tests will be conducted on the in-service test features of the installed SSLC equipment. These tests will confirm the basic functionality of each SSLC logic processing component. For ECCS functions, the tests will exercise all motor-operated valves and testable check valves of the interfacing systems unless excluded by interlock logic. The Surveillance Test Controller included in each SSLC division will simulate both normal and out-of-tolerance sequences of input signals for ECCS instrument channels.	6. Operability of the installed SSLC equipment when connected to its interfacing systems and power sources is considered acceptable under the following conditions (for each division): a. Programmed setpoints match interfacing safety system requirements. b. A half-scram condition exists when the RPS trip logic test switch is operated. A half-isolation condition exists when the MSIV trip logic test switch is operated. If trip logic bypass is applied, then a tripped state exists at the TLU output, but half-scram or -isolation is blocked. c. Operation of a divisional RPS trip switch causes a half-scram condition which cannot be bypassed. Operation of a second divisional RPS trip switch causes a full-scram condition. d. Operation of a divisional isolation switch causes a half-isolation condition of the eight MSIVs which cannot be bypassed. Operation of a second divisional isolation switch causes full closure of all eight MSIVs. e. Operation of individual MSIV open/close switches results in full opening and closing of individual MSIVs. f. Operation of individual MSIV test closure switches results in 10% closure. Reset position of switch returns MSIV to full open.

Table 3.4: Safety System Logic And Control (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. (continued)	6. (continued)	6. (continued) g. Surveillance Test Controller test sequence or manual control switch action results in required change of state of actuators and displays for each safety system test. h. Operation of manual control switches on main control panel (either flat panels or hard switches) activates each associated piece of equipment.
7. Full system test of SSLC with Essential Multiplexing System and other interfacing systems connected confirms SSLC response to safety system tests specified in each interfacing system ITAAC. Testing is conducted on the four divisions of SSLC simultaneously to verify 2-out-of-4 system operation.	7. Preoperational tests will be conducted to verify safety system logic functions of each interfacing safety system. These tests will verify support of scram capability, containment isolation capability, and ECCS initiation capability. The tests will include demonstration of ability to meet stated delay times and maximum response times. Tests will be conducted such that each display, alarm, annunciator, or other status indicator for each system is shown to be functional. SSLC is exercised in its five modes: a. <u>Normal operation</u>: Standby, monitoring of plant parameters. b. <u>Manual operation</u>: Flat panel and hard switches for test or emergency conditions. c. <u>Bypass operation</u>: Division-of-sensors bypass, Trip Logic bypass, and SLU bypass.	7. SSLC support of the interfacing safety systems is considered acceptable if reactor trip, containment isolation, and ECCS response of the installed equipment meet the acceptance criteria stated in each interfacing system ITAAC. The response time of each control action and trip output is within performance limits of each interfacing system. SSLC performance is acceptable in each of its five modes for the following conditions: a. <u>Normal operation</u>: Channel checks and channel calibrations can be performed. Plant process parameters can be visually displayed. b. <u>Manual operation</u>: Operation of each flat panel switch or hard switch causes actuation of associated equipment. Operation of system initiation switches produces valve lineup, pump start, and displays in accordance with safety system requirements.

Table 3.4: Safety System Logic And Control (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. (continued)	7. (continued) d. <u>Trip condition</u>: Reactor trip, Containment isolation, ECCS initiation, and output to non-safety systems. e. <u>Self-test</u>: Continuous internal self-diagnostics of software-based controllers and manually-initiated, off-line trip testing.	7. (continued) c. <u>Bypass operation</u>: (1). <u>Division-of-sensors bypass</u>: Bypass Unit in each division blocks trip signals in that division from being processed in the TLU or SLUs of any division. System reverts to 2-out-of-3 voting logic in each division during bypass and indicates bypass to operator at main control panel. System is returned to 2-out-of-4 condition when bypass is removed. (2). <u>Trip logic bypass</u>: Bypass Unit in each division blocks trip signals in that division from de-energizing RPS or MSIV load drivers associated with that division. (3). <u>SLU bypass</u>: Affected channel automatically continues normal operation after simulated loss of one redundant SLU. Manual SLU bypass after simulated loss of auto-bypass also permits normal operation. SLU inoperative condition and bypass status is displayed to the operator. d. <u>Trip condition</u>: SSLC supports each automatic and manual control action of the interfacing safety systems and delivers a trip or initiation output to the final system actuators or system logic

Table 3.4: Safety System Logic And Control (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. (continued)	7. (continued)	7. (continued) as required by a particular safety system, control system, or monitoring system. The associated alarm indications are displayed to the operator. e. <u>Self-test</u>: Internal self-diagnostics of software-based controllers detect and annunciate each actual or simulated fault. The automatic self-test cycle does not inhibit system response to incoming trip initiation signals or cause a spurious trip initiation signal.
8. SSLC provides safe-state response to loss of power source.	8. Tests will be conducted to verify that graceful degradation of SSLC system outputs occurs upon momentary or long-term loss of one division of the AC or DC power source or power to individual SSLC components. Tests will also confirm that reinitialization of system or component after power is restored does not impair normal system function.	8. SSLC response to loss of power is acceptable for the following conditions: a. Loss of one division of power does not cause false output trip or inadvertent initiation of final system actuators. Loss of power and loss of divisional trip signals are annunciated. b. Loss of power to individual component produces a safe-state output condition without extraneous false outputs (normally-energized outputs de-energize, normally-de-energized outputs remain de-energized).

Table 3.4: Safety System Logic And Control (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8. (continued)	8. (continued)	8. (continued) c. Restart (initialization) of component or system upon recovery of power does not cause inadvertent output action (outputs remain in safe-state condition until sensed inputs are evaluated in processing circuitry). e. Transient power loss (<1 second) causes no false output trip or inadvertent initiation of final system actuators or removal of previous tripped state.

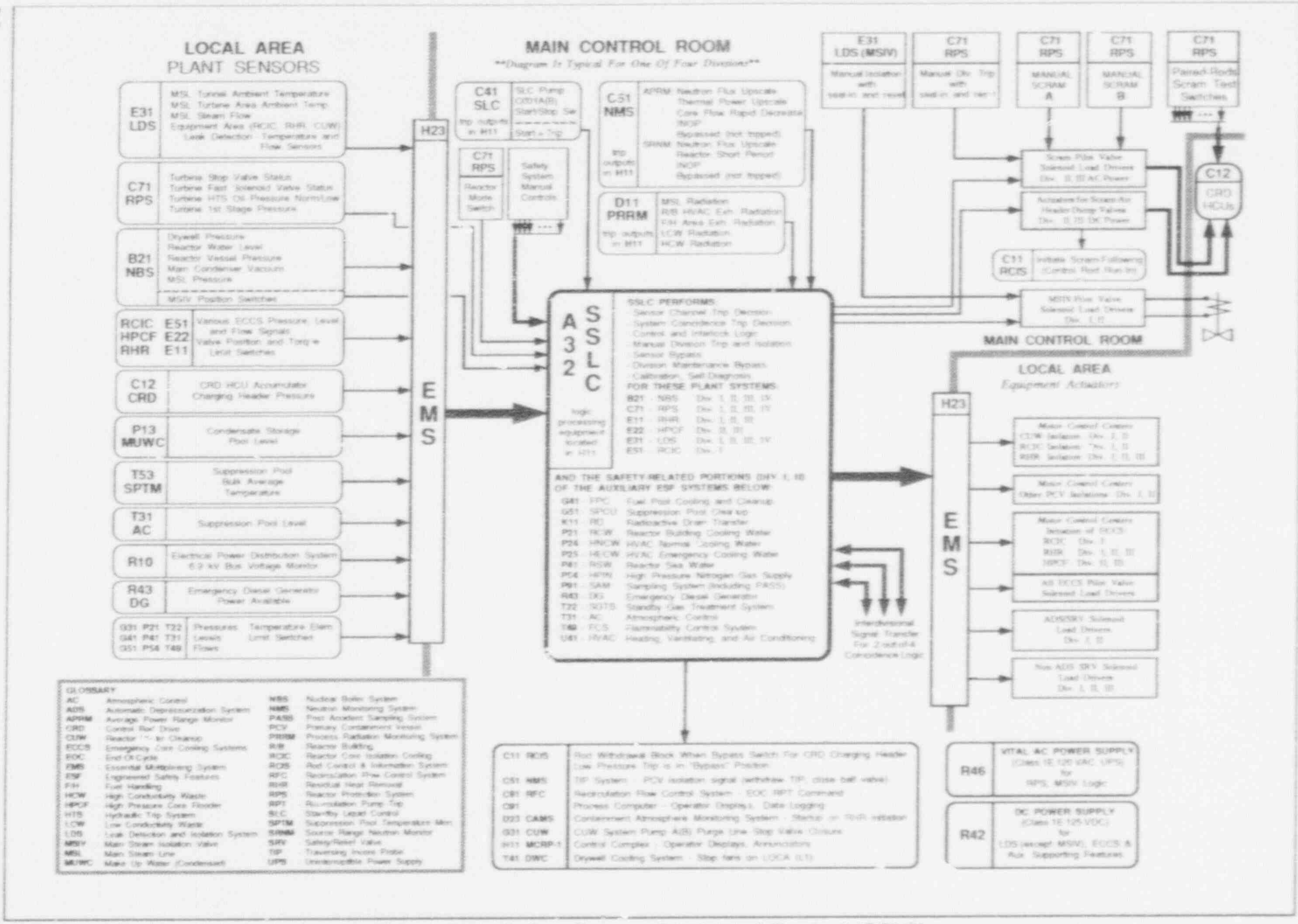
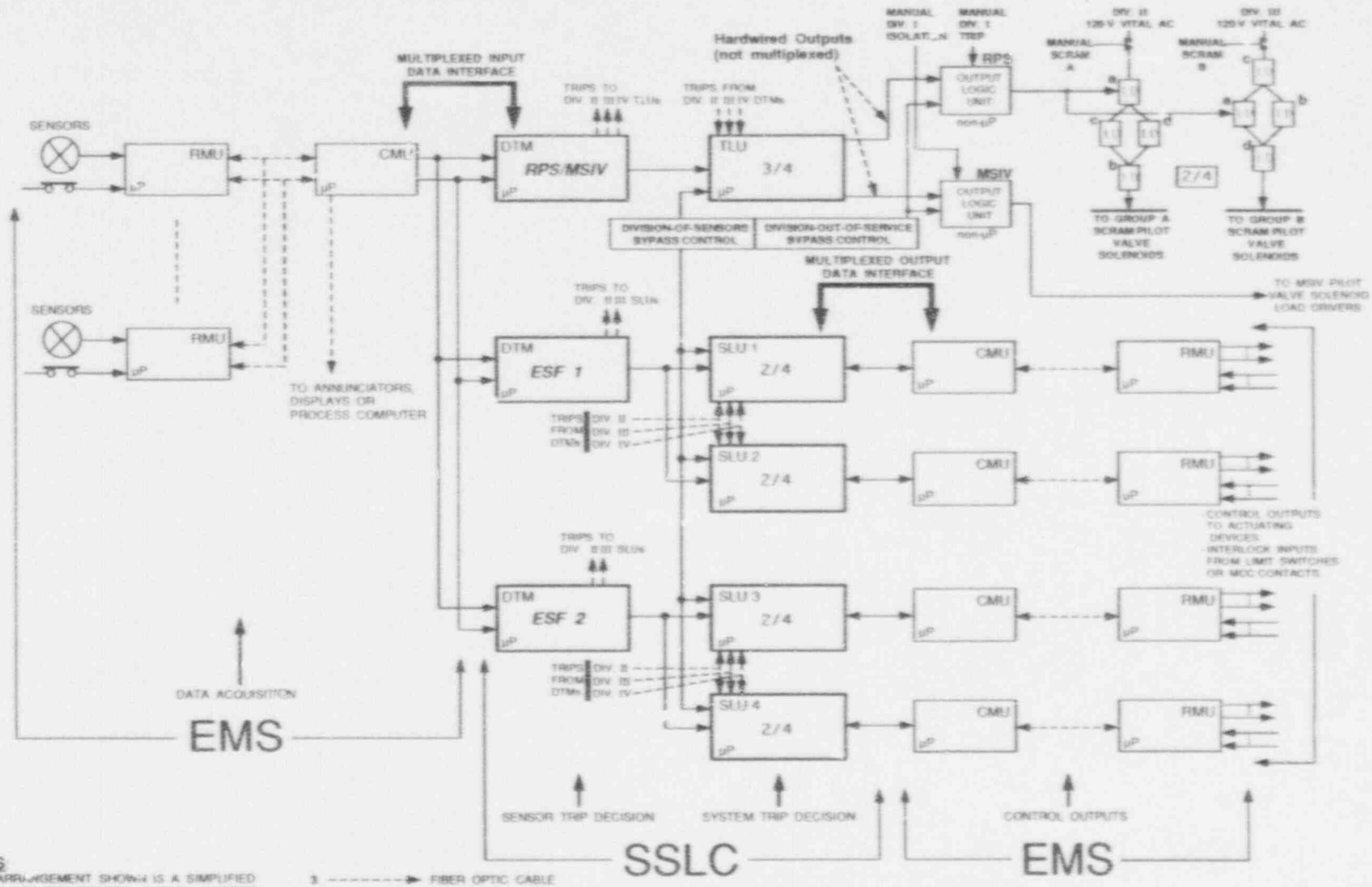


Figure 3.4a Safety System Logic and Control (SSLC)



NOTES:

1. THIS ARRANGEMENT SHOWN IS A SIMPLIFIED EXAMPLE FOR ONE DIVISION. ACTUAL QUANTITY AND INTERCONNECTIONS OF RMUs AND CMUs WILL BE DETERMINED WITHIN SCOPE OF EMS DESIGN. THERE ARE NO SLUs, CMUs, OR RMUs in DIV. IV.

2. NOT SHOWN FOR SSLC:
   A. OUTPUTS TO PROCESS COMPUTER OR ANNUNCIATORS ON DEDICATED FIBER OPTIC DATA LINKS.
   B. CONTROL SWITCH INPUTS.
   C. INPUTS FROM OTHER INTERFACING SYSTEMS.

3. - - - - - -► FIBER OPTIC CABLE
   ———————► METALLIC OR FIBER OPTIC CABLE

4. ABBREVIATIONS

CMU - CONTROL ROOM MULTIPLEXING UNIT
DTM - DIGITAL TRIP MODULE
EMS - ESSENTIAL MULTIPLEXING SYSTEM
ESF - ENGINEERED SAFETY FEATURES
LD - LOAD DRIVER
MSIV - MAIN STEAM ISOLATION VALVE
RMU - REMOTE MULTIPLEXING UNIT
RPS - REACTOR PROTECTION SYSTEM
SLU - SAFETY SYSTEM LOGIC UNIT
TLU - TRIP LOGIC UNIT
μP - MICROPROCESSOR

Figure 3.4b Safety System Logic & Control Block Diagram

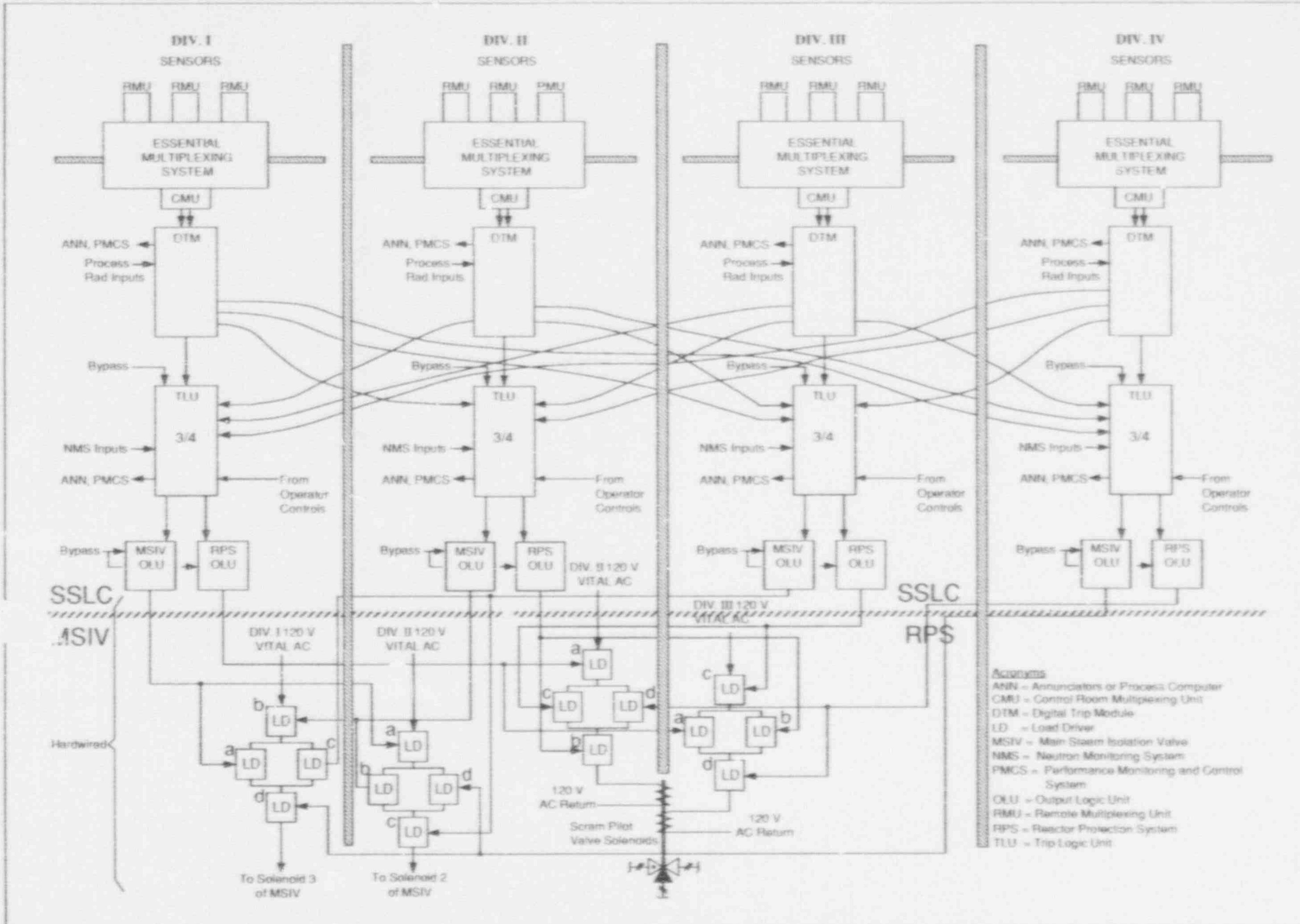


Figure 3.4c SSLC Configuration for RPS and MSIV

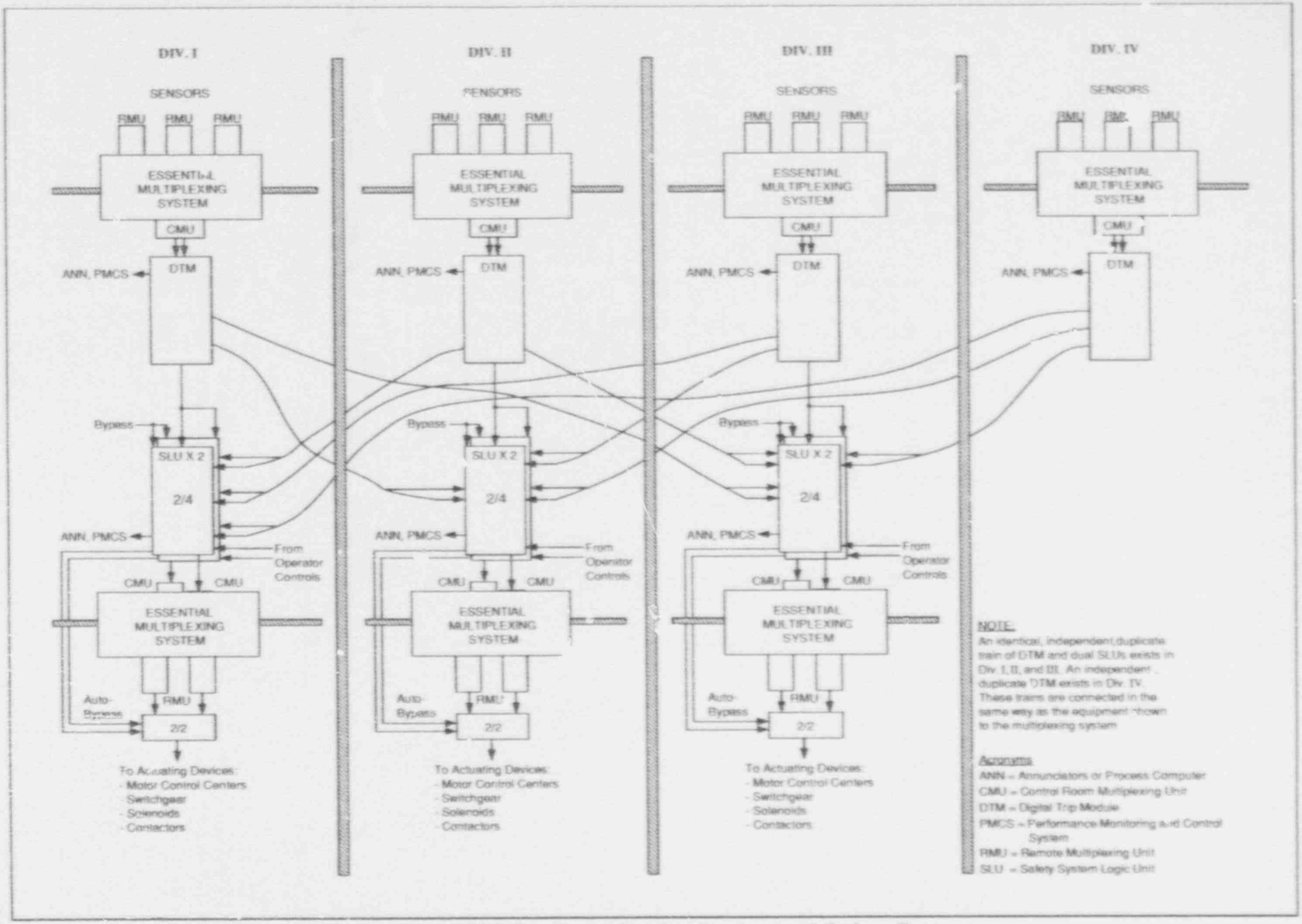
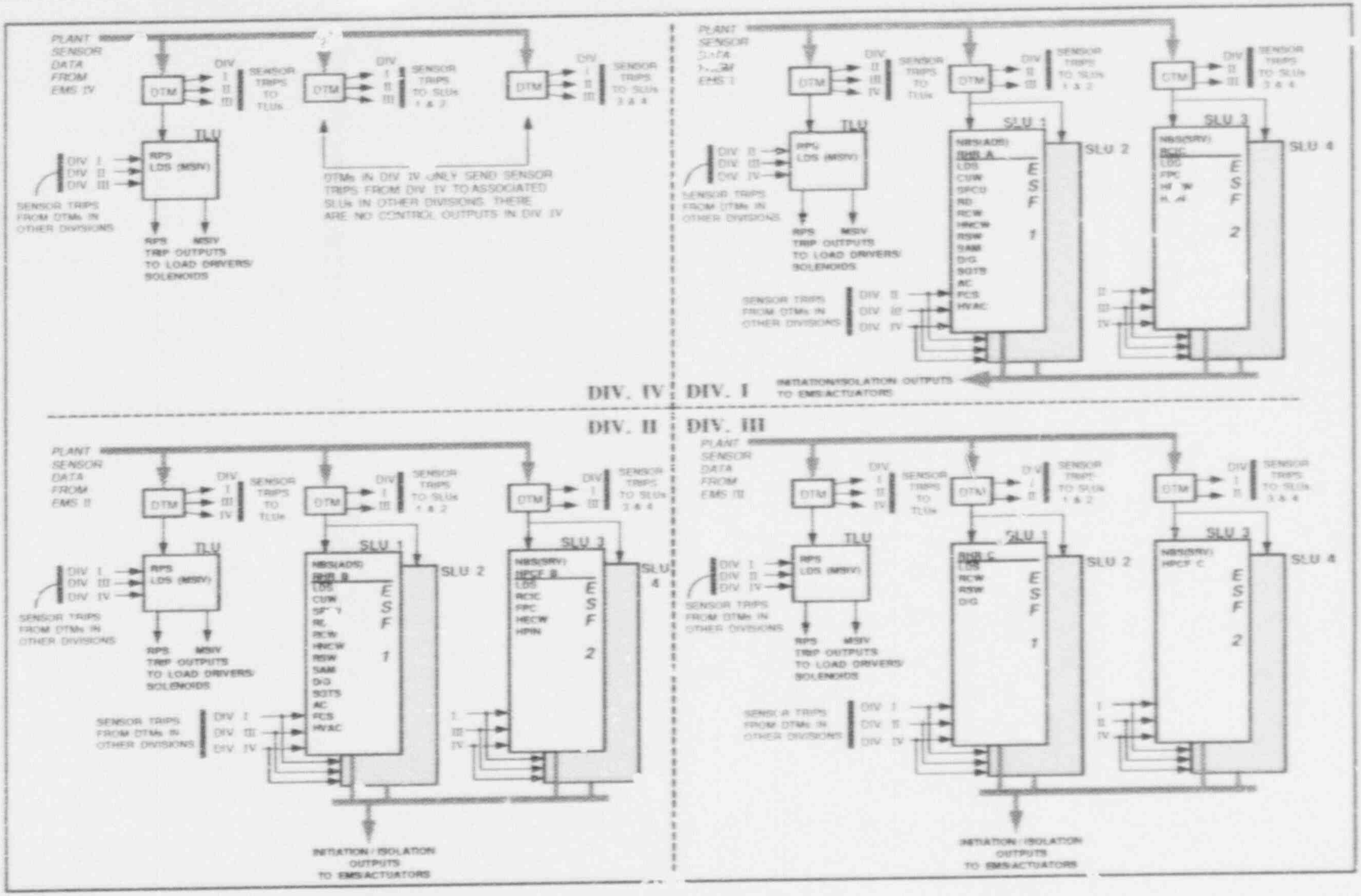


Figure 3.4d SSLC Configuration for Engineered Safety Features



ABBREVIATIONS:

DTM = DIGITAL TRIP MODULE
EMS = ESSENTIAL MULTIPLEXING SYSTEM
SLU = SAFETY SYSTEM LOGIC UNIT
TLU = TRIP LOGIC UNIT

AC = ATMOSPHERIC CONTROL
CUW = REACTOR WATER CLEANUP
D/G = DIESEL GENERATOR
ESF = ENGINEERED SAFETY FEATURES
FCS = FLAMMABILITY CONTROL SYSTEM
FPC = FUEL POOL COOLING & CLEANUP
HECW = HVAC EMERGENCY COOLING WATER
HNCW = HVAC NORMAL COOLING WATER
HPIN = HIGH PRESSURE NITROGEN SUPPLY
HVAC = HEATING, VENTILATING & AIR CONDITIONING
LDS = LEAK DETECTION & ISOLATION SYSTEM

MSIV = MAIN STEAM ISOLATION VALVE
NBS = NUCLEAR BOILER SYSTEM
RCIC = REACTOR CORE ISOLATION COOLING
RCW = REACTOR BUILDING CLOSED COOLING WATER
RD = RADIOACTIVE DRAIN TRANSFER
RHR = RESIDUAL HEAT REMOVAL
RPS = REACTOR PROTECTION SYSTEM
RSW = REACTOR SEA WATER
SAM = SAMPLING SYSTEM
SGTS = STANDBY GAS TREATMENT SYSTEM
SPCU = SUPPRESSION POOL CLEANUP

Figure 3.4e Assignment of Interfacing Safety System Logic to SSLC Controllers

3.5 Software Development

Design Description

The certified design uses microprocessor-based digital equipment to perform selected safety-related functions. Development of the necessary software is dependent upon the as-procured hardware and is thus not part of the certified design. The process to be used for software development and implementation will be in full compliance with the regulatory requirements and industrial standards governing these activities. These requirements will apply to: a) each ABWR safety system that uses the safety-related software functions of the Safety System Logic and Control (SSLC) equipment and b) other safety-related equipment that contains software to perform safety functions.

Inspections, Tests, Analyses and Acceptance Criteria

Table 3.5, together with Appendices A, B, and C, provides a definition of the processes that will be used to demonstrate compliance with the requirements governing development and implementation of software for safety-related functions. This material is structured as follows:

Table 3.5:	Generic inspections, tests, analyses, and acceptance criteria (ITAAC) material for the overall software development process. Key elements of this process are a Software Management Plan, Configuration Management Plan, and a Verification and Validation (V&V) Plan.
Appendix A:	Design Acceptance Criteria (DAC) for the Software Management Plan
Appendix B:	Design Acceptance Criteria (DAC) for the Configuration Management Plan
Appendix C:	Design Acceptance Criteria (DAC) for the Verification and Validation (V&V) Plan

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. A plan shall be developed for software used in microprocessor-based equipment that performs safety-related functions. The plan shall describe the organizational and procedural aspects of software development and shall comprise the following elements: - Software Management Plan - Configuration Management Plan - Verification and Validation (V&V) plan	1. Review: - Software Management Plan - Configuration Management Plan - Verification and Validation Plan	1. The overall development plan documents the requirements and methodology for achieving the software attributes of consistency, accuracy, error tolerance and modularity. The plan includes the methodology for assuring the software is both auditable and testable during the design, implementation and integration phases. Each element of the plan contains the following items as a minimum: a. Software Management Plan establishes standards, conventions and design processes for the design, development, and maintenance of safety-related software. The plan meets the design acceptance criteria described in Appendix A. b. Configuration Management Plan establishes a formal set of standards and procedures to provide visible status and control of software documentation. The following basic elements are addressed: (1) Unique identification of each software documentation item (2) Management of software documentation change control (3) Accounting methods to provide visibility and traceability for all changes to baseline product software (4) Verification steps required to assure proper adherence to software design requirements

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
		1. (Continued) The plan meets the design acceptance criteria described in Appendix B. c. Verification and Validation Plan establishes verification reviews and validation testing procedures with the following components: (1) Independent design verification (2) Baseline reviews (3) Testing (a) Unstructured testing (b) Formal validation testing (4) Firmware issue and validation procedure (5) Procedure for future revisions The plan meets the design acceptance criteria described in Appendix C.
2. The software design documentation shall meet the requirements of each element of the software development plan described in Item 1.	2. Review design documentation: - Hardware/Software System Specification - Software Requirements Specification - Software Design Specification - Hardware Requirements Specification - Hardware Design Specification	2. The documentation complies with the requirements of the software development plan. The design documentation generated by the definition and planning process described in Appendix A allows correlation of the design elements with each specific software requirement as determined by the V&V process described in Appendix C. The computer system hardware documentation identifies the hardware requirements that impact software.

Table 3.5: Software for Programmable Digital Compu[illegible] ty-[illegible]ted A[illegible]plications (Continued)

Inspections, Tests, Analyses a[illegible] teria

Certified Design Commitment	Inspections, Tests, A[illegible]	Acceptance Criteria
3. The generation of documentation for: (1) software implementation and (2) the integration of hardware and software into the final product shall follow the process described in the elements of the software development plan.	3. Review the software development plan.	3. The documentation for software implementation and hardware/software integration testing meets the requirements of the software development plan, as shown in Appendices A, B, and C.
4. The assembled, final production computer system shall be exercised through static and dynamic simulations of input signals present during normal operation and design basis event conditions requiring computer system action. The validation test plan shall identify the validation tests for each software-based system component of Safety System Logic and Control (SSLC). The plan shall also include tests that validate correct operation for each safety system requirement of the systems that interface with SSLC. The requirements are those stated in the System Design Specification of each interfacing safety system.	4. Review formal (verified) validation test report.	4. The test report summarizes the results of the computer system validation testing and shows how the system is in compliance with the requirements. The test report identifies the validation tests for each computer system and safety system requirement. In addition, the required input signals and their values, the anticipated output signals, and the acceptance criteria are stated. The test report identifies the hardware and software used, test equipment and calibrations, simulation models used, test results, and discrepancies and corrective actions. The test plan was developed, the tests executed, and the test results evaluated by individuals who did not participate in the design or implementation phases.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix A: Design Acceptance Criteria for Software Management Plan

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The standards, conventions, and design processes to be followed during the design, development, and maintenance of safety-related software shall be established in the software management plan.	1. A review shall be performed of the contents of the software management plan.	1. A software management plan has been issued.
2. The software management plan shall define and document the following major design phases of the software engineering process: a. Definition and Planning b. Product Performance Definition c. High Level Software Design d. Detailed Design/Code/Module Test e. Integration Test f. Validation and Firmware Issue g. Firmware Release	2. A review shall be performed of the contents of the software management plan.	2. The plan contains a description of each specified phase of the software engineering process. A particular design phase shall be verified with respect to the set of documents produced for that phase. These documents are listed in the design commitments in the following sections. See Appendix C for details of, and acceptance criteria for, the verification and validation process.
3. <u>Definition and Planning Phase</u>. This phase comprises the identification of applicable requirements (contractual or from design specifications) and confirmation of suitability of the software planning documents. The documents required to be baselined at the completion of this design phase are: a. Design Requirements b. Software Configuration Management Plan c. Software Management Plan d. Software Verification and Validation Plan e. Baseline Review Record	3. A review shall be performed of the contents of the software management plan. <u>Definition of baseline</u>: A set of documents, assumptions, and open items that reflect the current state of a design phase and define the design input for the next design phase.	3. The plan states that the committed documents are the baseline of the Definition and Planning Phase. The plan also states that all required verification reviews are to be completed before the design moves to the next phase, as attested to in the Baseline Review Record.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix A: Design Acceptance Criteria for Software Management Plan (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4. Product Performance Definition: Defines the general product design and the split between hardware and software. The documents required to be baselined at the completion of this design phase are: a. Product Schematic b. Product Performance Specification, including Software Requirements c. Product User's Manual d. Communications Protocols e. Baseline Review Record	4. A review shall be performed of the contents of the software management plan.	4. The plan states that the committed documents are the baseline of the Product Performance Definition Phase. The plan also states that all required verification reviews are to be completed before the design moves to the next phase, as attested to in the Baseline Review Record.
5. High Level Software Design: This phase comprises the design of the software architecture and structure and the determination of general module functions. The documents required to be baselined at the completion of this design phase are: a. Software Design Specification b. Baseline Review Record	5. A review shall be performed of the contents of the software management plan.	5. The plan states that the committed documents are the baseline of the High Level Software Design Phase The plan also states that all required verification reviews are to be completed before the design moves to the next phase, as attested to in the Baseline Review Record.
6. Detailed Design/Code/Module Test: This phase comprises detailed design of the software and testing of individual software modules by the designer. The documents required to be baselined at the completion of this design phase are: a Source Code b. Module Testing Report c. Baseline Review Record	6. A review shall be performed of the contents of the software management plan. Definition of module: Executable computer code that implements a functional requirement or part of a functional requirement; normally the smallest segment of code controlled by the operating system.	6. The plan states that the committed documents are the baseline of the Detailed Design/Code/Module Test Phase. The plan also states that all required verification reviews are to be completed before the design moves to the next phase, as attested to in the Baseline Review Record. Someone other than the designer reviews the software modules.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix A: Design Acceptance Criteria for Software Management Plan (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. Integration Test: This phase comprises the testing that evaluates performance and adequacy of the software when installed in its destined hardware. The documents required to be baselined at the completion of this design phase are: a. Integration Test Report b. Baseline Review Record	7. A review shall be performed of the contents of the software management plan.	7. The plan states that the committed documents are the baseline of the Integration Test Phase. The plan also states that all required verification reviews are to be completed before the design moves to the next phase, as attested to in the Baseline Review Record.
8. Validation and Firmware Issue: This phase comprises the generation and use of the procedures necessary to perform final testing on a production instrument and to assure the quality of the delivered software. The documents required to be baselined at the completion of this design phase are: a. Validation Test Plan and Procedure b. Validation Test Report c. Firmware Release Description d. Issued Firmware (object code) e. Baseline Review Record	8. A review shall be performed of the contents of the software management plan. Definition of firmware: Object (machine) code contained in non-volatile memory, typically PROM or EPROM.	8. The plan states that the committed documents are the baseline of the Validation and Firmware Issue Phase. The Firmware Release Description contains the following information: a. The means by which the source code was compiled, linked, and located. b. The means by which the master PROMs were generated. c. A record of hardware and software tools used to develop the firmware. The plan also states that all required verification reviews are to be completed before release of the firmware for production, as attested to in the Baseline Review Record.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix B: Design Acceptance Criteria for Configuration Management Plan

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Development of software for the microprocessor-based safety systems shall be controlled according to a configuration management plan	1. A review shall be performed of the contents of the configuration management plan.	1. A configuration management plan has been issued.
2. The configuration management plan will define the purpose and scope of the plan with emphasis on the groups to which it applies and the specific product which is to be developed. The product description shall include both executable and non-executable material.	2. A review shall be performed of the contents of the configuration management plan.	2. The configuration management plan identifies each group which develops and/ or maintains software for safety systems. The plan includes both executable and non-executable portions of the design.
3. The configuration plan shall describe the organizational responsibilities. The organizational independence or dependence of the groups responsible for the software configuration shall be specifically described. The plan shall describe a function independent of the software designers that is responsible for verifying that the software is maintained under this plan. The plan shall detail the relationships of the configuration control with the software QA, development, and other groups.	3. A review shall be performed of the contents of the configuration management plan.	3. The configuration plan describes the organizational independence and responsibilities.

Table 3.5 Software for Programmable Digital Computers in Safety-related Applications

Appendix B: Design Acceptance Criteria for Configuration Management Plan (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4. Applicable procedures, such as standards for the designation of software versions, shall be described in the plan or specifically referenced. All software shall be identified such that the version can be verified directly, either embedded in the software if in a non-programmable/erasable format or permanently inscribed directly on the component.	4. A review shall be performed of the contents of the configuration management plan.	4. The plan describes the procedures for implementation of the plan.
5. The plan shall describe the audits and reviews that are to be performed to verify that the software is being maintained under configuration management. The plan shall describe a procedure for corrective actions if any problems are discovered.	5. A review shall be performed of the contents of the configuration management plan.	5. The plan describes audits and reviews and describes a procedure for corrective actions.
6. The configuration management of tools, techniques, and methodologies shall be specifically delineated. The plan shall address control of development methods to be used (such as formal specification) and tools (such as compilers).	6. A review shall be performed of the contents of the configuration management plan.	6. The plan describes control of tools and methodologies.
7. The plan shall describe the method of records collection and retention.	7. A review shall be performed of the contents of the configuration management plan.	7. The plan describes the record storage plan.
8. The plan shall address control of the final user documentation and the information to be supplied. The method of informing the user of each product of known faults, failures, and changes shall be specifically described.	8. A review shall be performed of the contents of the configuration management plan.	8. The plan identifies the method by which faults, failures, and changes are identified to the affected user.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix B: Design Acceptance Criteria for Configuration Management Plan (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9. The configuration management plan shall be in place and approved by the implementor prior to the first concept development phases of software development.	9. A review of this plan shall be conducted during a product's Definition and Planning design phase (see Appendix A).	9. The configuration management plan will be approved and in place at the beginning of the project.
10. The configuration management plan shall require that the design documents (such as software requirements specifications) shall provide specific reference to the applicable configuration management plan. The plan shall define procedures for change control, including change request, evaluation, approval, and implementation.	10. A review shall be performed of the contents of the configuration management plan.	10. The plan requires that the design documents reference the configuration management plan.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix C: Design Acceptance Criteria for Verification and Validation Plan

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Verification reviews and validation testing shall be used to assure software quality. The methodology and requirements for these techniques are described in the Verification and Validation (V&V) Plan.	1. A review of this plan shall be conducted during a product's Definition and Planning design phase (see Appendix A).	1. The review assures the suitability of the plan and notes any needed modifications. The V&V plan will be approved and in place at the beginning of the project.
2. The V&V process shall comprise a combination of the following activities: a. Informal reviews b. Independent design verifications c. Baseline reviews d. Layered testing (unstructured testing and validation testing)	2. A review shall be performed of the contents of the V&V plan.	2. The plan contains a description of the committed activities. The activities are defined in the following sections.
3. Informal Review: Informal reviews shall be used to resolve problems, evaluate alternate approaches, tentatively confirm adequacy of a solution or processing approach, or other design evolution activity.	3. A review shall be performed of the contents of the V&V plan.	3. The plan describes the uses and limitations of informal reviews and their methodology. This activity does not confirm compliance with any external requirements.
4. Independent Design Verification: The product assurance process shall provide controlled, independent, documented confirmation that the design meets requirements. The process shall address the following aspects of the design as a minimum: a. Quality b. Safety c. Reliability d. Performance	4. A review shall be performed of the contents of the V&V plan.	4. The plan describes the independent design verification process. Confirmation of design adequacy is performed by knowledgeable individuals other than those responsible for the design.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix C: Design Acceptance Criteria for Verification and Validation Plan (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. <u>Baseline Reviews</u>: Formal, independent evaluations of the design process, and the effectiveness and completeness of the process to specified points in the design, shall be performed. Baseline reviews are required during the following software development phases: a. Definition and Planning b. Product Performance Definition c. High Level Software Design d. Detailed Design/Code/Module Test e. Integration Test f. Validation and Firmware Issue g. Firmware Release	5. A review shall be performed of the contents of the V&V plan.	5. The plan describes the baseline review process. As a minimum, each review evaluates the following areas: a. Adequacy of documentation b. Adequacy of design process c. Adequacy of test methods d. Adherence to software management plan, configuration management plan and V&V plan Baseline reviews are performed by knowledgeable individuals other than those directly responsible for the design.
6. <u>Unstructured Testing</u>: No formal test plan or procedure shall be required. The following unstructured tests shall be performed during the design process: a. Exploratory testing evaluates implementation ideas of the designer. b. Module testing confirms the performance of individual software modules via emulation of hardware components c. Integration testing is performed on prototype hardware and confirms that all instrument functions, including self-test (if applicable), work properly	6. A review shall be performed of the contents of the V&V plan.	6. The plan describes the testing processes, which are documented as follows: a. Exploratory testing requires no formal certification, but may be documented by design notes. b. Module testing is documented in the Module Test Report. c. Integration test results are documented in the Integration Test Report. Concurrence on test adequacy is achieved during the Integration Test Baseline Review.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix C: Design Acceptance Criteria for Verification and Validation Plan (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. Validation Testing: This process confirms that the final version of the software (firmware) loaded in the production (or fully equivalent) hardware performs all required functions. In addition, displays (if any) are confirmed to be consistant with the final version of the User's Manual.	7. A review shall be performed of the contents of the V&V plan.	7. The plan describes the validation testing process. Validation testing is performed as specified in a formal documented procedure which is written by an individual not responsible for software design and is verified against requirements and performance specifications to confirm that all functions are tested. Results of the test are documented, along with a resolution of anomalies, in a Validation Test Report. Validation testing shall be performed by individuals other than the instrument software designers.
8. Firmware Verification and Issue : The final software (firmware) shall be verified prior to issue.	8. A review shall be performed of the contents of the V&V plan.	8. The plan describes the final verification process for firmware. The process includes structured confirmation that the design has been tested or verified by formal review, shows compliance with all requirements, and all testing has been completed and open items resolved.
9. Software Changes: Changes to the software after release shall be handled in accordance with the software management plan and authorized change control provisions.	9. A review shall be performed of the contents of the V&V plan.	9. The plan describes the software change process and required V&V tests. Steps of the V&V process will be repeated as applicable, including repeat of all or part of the Validation Test.

3.6 Human Factors Engineering

Design Description

[Later]

3.7 Radiation Protection

Design Description

The ABWR design provides radiation protection features that will keep exposures for both plant personnel and the general public well below allowable limits. These low exposure conditions are achieved by an integrated approach that recognizes the contribution of both shielding provisions and ventilation system designs that control airborne contaminants. Monitoring of radiation levels is an integral part of the plant radiation protection strategy.

The plant design provides radiation shielding for rooms, corridors and operating areas commensurate with their occupancy requirements and thus maintains radiation exposures to plant personnel as low as reasonably achievable. Maintenance of plant components is achieved without significant radiation exposure from adjacent plant systems or equipment by use of shielded cubicles, labyrinth access and provisions for temporary shielding. Under accident conditions, plant shielding designs permit operators to perform required safety functions in vital areas of the plant. In addition to protection of operating personnel, the plant design provides radiation shielding which maintains radiation exposure to the general public as low as is reasonably achievable.

Plant ventilation systems insure that concentrations of airborne radionuclides are maintained at levels consistent with personnel access requirements. In addition, airborne radioactivity monitoring is provided for those normally occupied areas of the plant in which there exists a significant potential for airborne contamination. The equipment for measurement of airborne particulation concentrations is not in the scope of this design and is specified as an interface in Section 4.8.

Inspections, Tests, Analyses and Acceptance Criteria

Tables 3.7a and 3.7b provide a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the ABWR plant shielding, ventilation and airborne monitoring equipment.

Table 3.7a: Plant Shielding Design

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The plant design shall provide radiation shielding for rooms, corridors and operating areas commensurate with their occupancy requirements to maintain radiation exposures to plant personnel as low as reasonably achievable.	1. An analysis of the expected radiation levels in each plant area will be performed to verify the adequacy of the shielding design. This analysis shall consider the following: a. Confirmatory calculations shall consider all significant radiation sources (greater than 5% contribution) for an area. Radiation source strength in plant systems and components will be determined based upon an assumed source term of 100,000 µCurie/second offgas release rate (after 30 minutes decay), a 200 µCurie/gram-steam N-16 source term at the vessel exit nozzle, and a core inventory commensurate with a 4005 MWt equilibrium core at 51.6 kwatt/liter. All source terms shall be adjusted for radiological decay and buildup of activated corrosion and wear products. b. Commonly accepted shielding codes, using nuclear properties derived from well known references (such as Vitamin C and ANSI/ANS-6.4) shall be used to model and evaluate plant radiation environments. 1) For non-complex geometries, point kernal shielding codes (such as QAD or GGG) shall be used. 2) For complex geometries, more sophisticated two or three dimensional transport codes (such as DORT or TORT) shall be used.	1. Maximum expected area radiation levels (not contact) are no greater than the radiation level specified for the zone with the major part of the zone (defined as 80% by area) well within (25% or less) of the radiation zone designation, for each plant area, as indicated in Figures 3.7a through 3.7c.

Table 3.7a: Plant Shielding Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
	c. In any calculation, a safety factor shall be applied based upon benchmark comparisons of the code and data collected from known and measured environments.	
2. The plant design shall provide shielded cubicles, labyrinth access, and space for temporary shielding to allow for maintenance of plant components without significant radiation exposure from adjacent plant systems or equipment.	2. Using the methods identified in (1) above, radiation levels present in areas where maintenance is performed shall be evaluated for the contribution from adjacent high radiation areas and equipment.	2. Shielding design (with temporary shielding installed, where appropriate) is such that radiation from adjacent areas shall contribute no more than a small fraction (10% or less) of the radiation field intensity or less than 0.06mrem/hr whichever is larger, in plant areas where maintenance is performed.
3. The plant radiation shielding design shall permit operators to perform required safety functions in vital areas of the plant (including access and egress of these areas) under accident conditions.	3. An analysis of the expected high radiation levels in each area which will or may require occupancy to permit an operator to aid in the mitigation of or recovery from an accident (vital area) shall be performed to verify the adequacy of the plant shielding design. This analysis shall use calculational methods consistent with (1.b) above and a radiation source term (adjusted for radioactive decay) based on the following: a. Liquid containing systems: 100% of the core equilibrium noble gas inventory, 50% of the core equilibrium halogen inventory and 1% of all others are assumed to be mixed in the reactor coolant and recirculation liquids recirculated by the residual heat removal system (RHR), the high	3. Under accident conditions, radiation shielding design allows access, occupancy and egress of vital areas such that personnel radiation exposures do not exceed 5 rem to the whole body, or its equivalent, for the duration of the accident (based on the required frequency of access to each vital area). For areas requiring continuous occupancy (such as the control room), local radiation hot spots shall not exceed 15 mrem/hr (averaged over 30 days).

Table 3.7a: Plant Shielding Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
	3. (Cont.) pressure core flooder (HPCF), and the reactor core isolation cooling (RCIC) systems. b. Gas containing systems: 100% of the core equilibrium noble gas inventory and 25% of the core equilibrium halogen activity are assumed to be mixed in the containment atmosphere. For vapor containing systems (such as the main steam lines) these core inventory fractions are assumed to be contained in the reactor coolant vapor space.	
4. The plant design shall provide radiation shielding to maintain radiation exposure to the general public as low as is reasonably achievable.	4. Using the methods identified in (1) above, the radiation dose to the maximally exposed member of the general public from direct and scattered shall be determined.	4. The radiation dose to the maximally exposed member of the public is a small fraction (10% or less) of the dose limit to a member of the public listed in 40CFR190.

Table 3.7b: Ventilation and Airborne Monitoring

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Plant design shall provide adequate containment of airborne radioactive materials and the ventilation system will ensure that concentrations of airborne radionuclides are maintained at levels consistent with personnel access requirements.	1. Expected concentrations of airborne radioactive material shall be calculated by nuclide for normal plant operations, anticipated operational occurrences for each equipment cubicle, corridor, and operating area requiring personnel access. Calculations shall consider: a. Design ventilation flow rates for each area, b. Typical leakage characteristics for equipment located in each area, and c. A radiation source term in each fluid system shall be determined based upon an assumed offgas rate of 100,000 μ Curie/second (30 minute decay) appropriately adjusted for radiological decay and buildup of activated corrosion and wear products.	1. Calculation of radioactive airborne concentration shall demonstrate that: a. For normally occupied rooms and areas of the plant (i.e. those areas requiring routine access to operate and maintain the plant) equilibrium concentrations of airborne nuclides will be a small fraction (10% or less) of the occupational concentration limits listed in 10 CFR 20 Appendix B. b. For rooms that require infrequent access (such as for non-routine equipment maintenance), the ventilation system shall be capable of reducing radioactive airborne concentrations to (and maintaining them at) the occupational concentration limits listed in 10CFR20 Appendix B during the periods that occupancy is required. c. For rooms that seldom require access (such as tank rooms), plant design shall provide sufficient containment and ventilation to ensure airborne contamination does not spread to other areas.

Table 3.7b: Ventilation and Airborne Monitoring (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
2. Airborne radioactivity monitoring shall be provided for those normally occupied areas of the plant in which there exists as significant potential for airborne contamination (greater than 0.1 per year)	2. An analysis shall be performed to identify the plant areas that require airborne radioactivity monitoring.	2. Airborne radioactivity monitoring system shall: a. Have the capability of detecting the time integrated change in concentrations of the most limiting particulate and iodine radionuclides in each area equivalent to the occupational concentration limits in 10CFR20, Appendix B for 10hours. b. Provide a calibrated response, representatvie of the concentrations within the area (i.E. air sampling monitors in ventilation exhaust streams shall collect and isokinetic sample). c. Provide local audible alarms (visual alarms in high noise areas) with variable alarm set points, and readout/ annunciation capability.

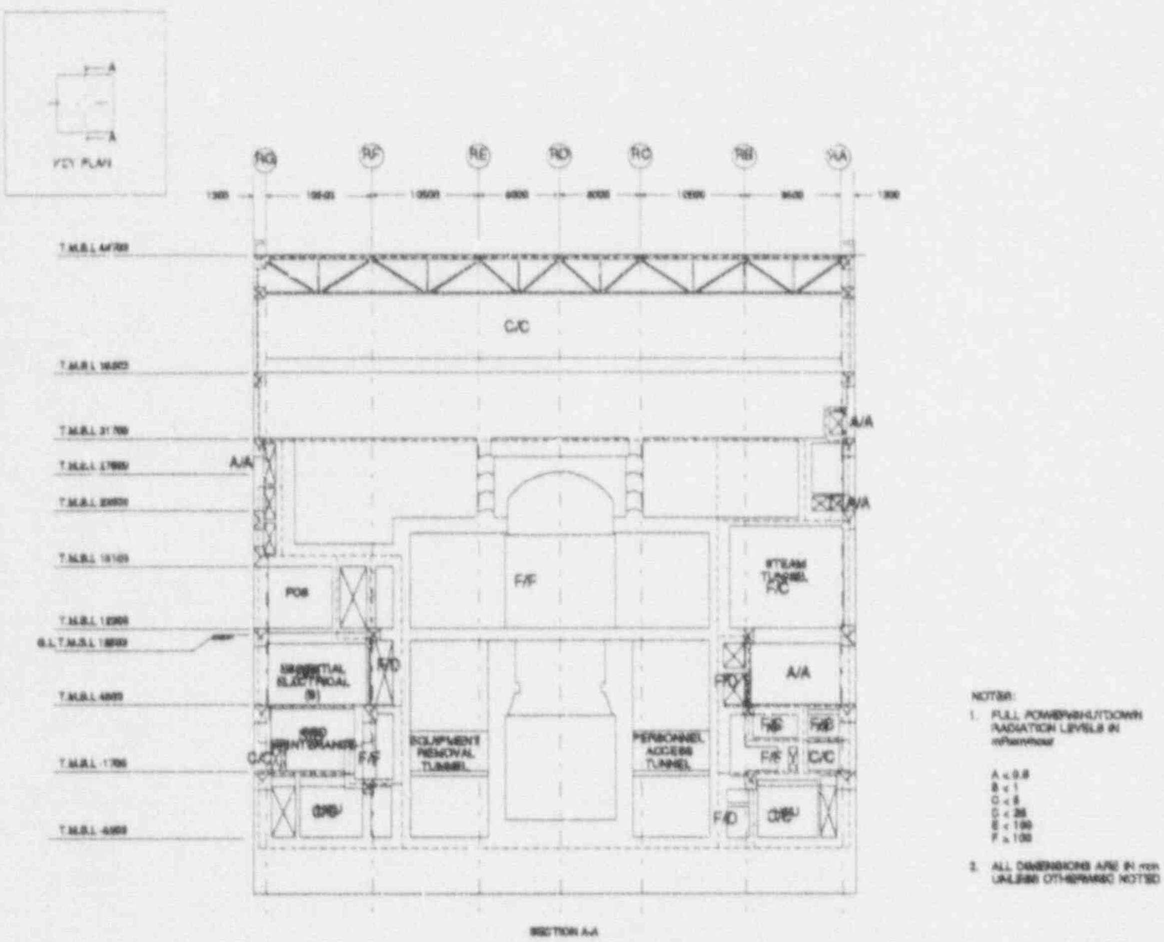
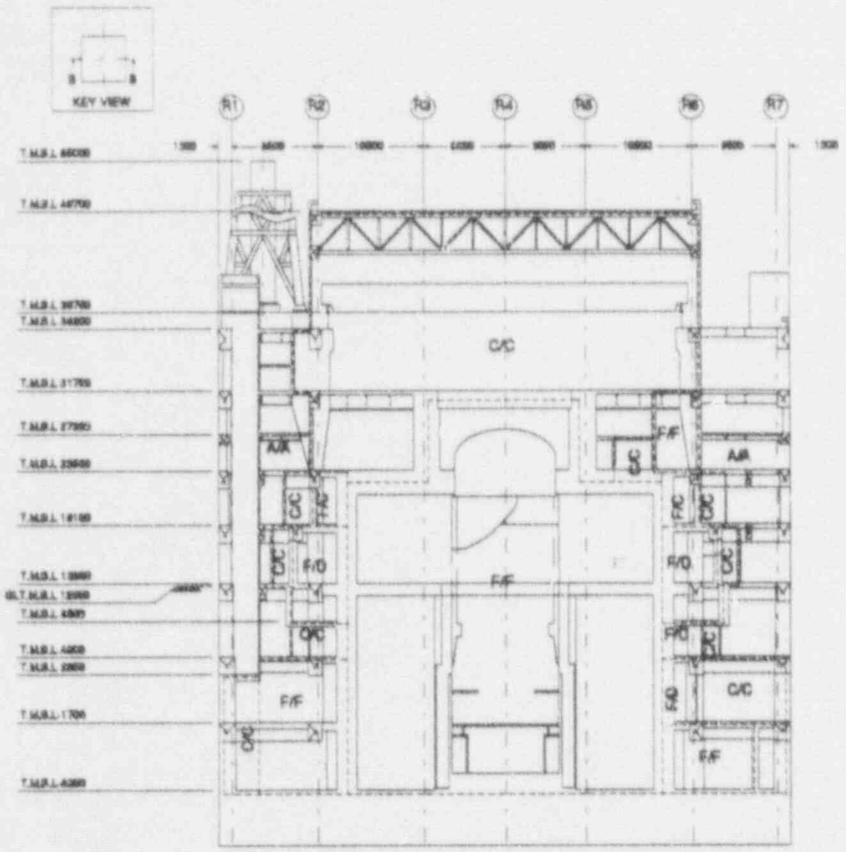


FIGURE 3.7a REACTOR BUILDING RADIATION ZONE MAP FOR FULL POWER AND SHUTDOWN OPERATIONS CROSS SECTION VIEW A-A

Figure 3.7a



SECTION B-B

FIGURE 3.7b REACTOR BUILDING
RADIATION ZONE MAP FOR
FULL POWER AND SHUTDOWN OPERATIONS
CROSS SECTION VIEW B-B

NOTES:

1. FULL POWER/SHUTDOWN RADIATION LEVELS IN mRem/hour

   A < 0.5
   B < 1
   C < 5
   D < 25
   E < 100
   F ≥ 100

2. ALL DIMENSIONS ARE IN mm UNLESS OTHERWISE NOTED

Figure 3.7b

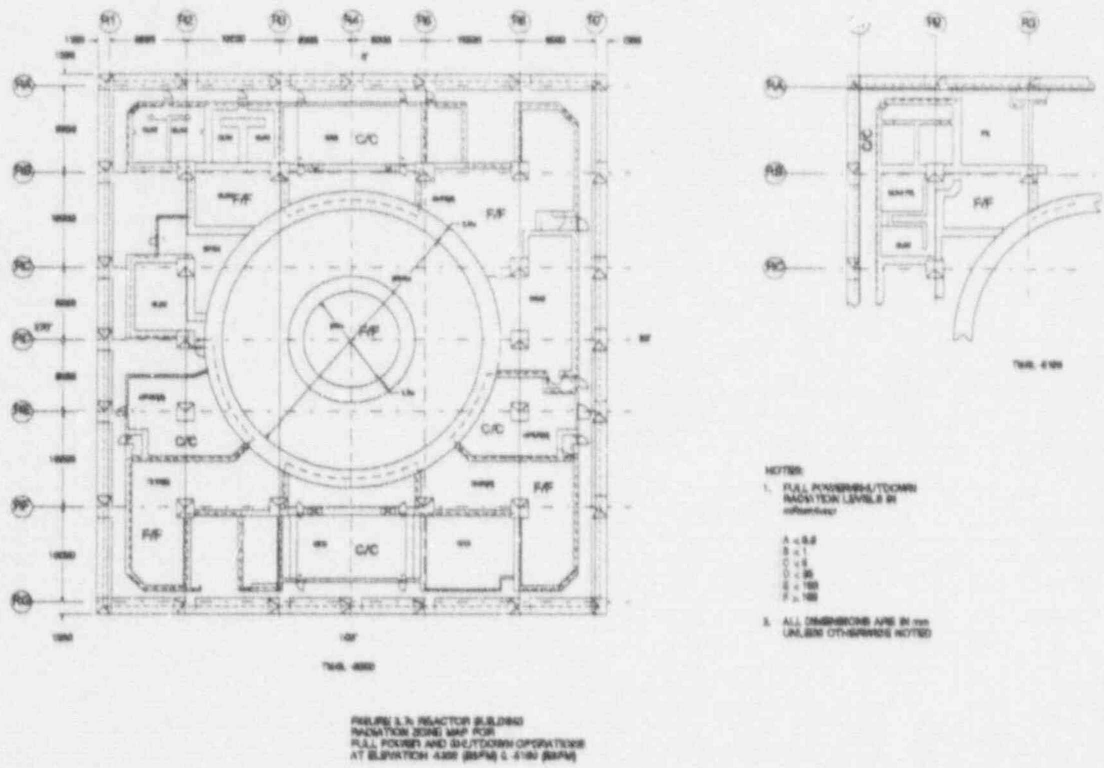


Figure 3.7c

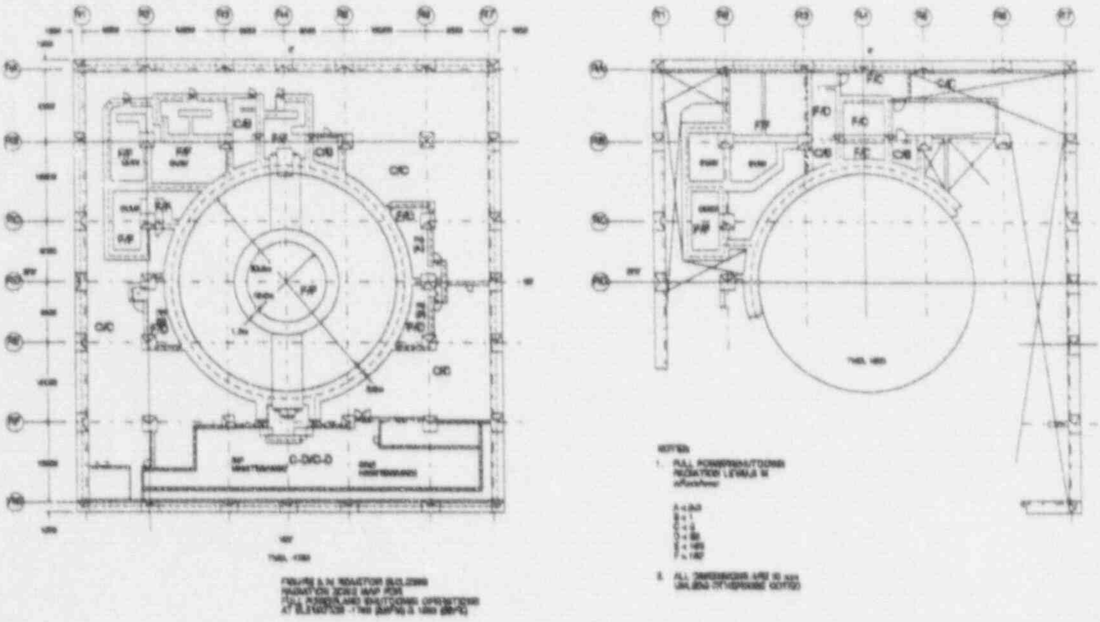
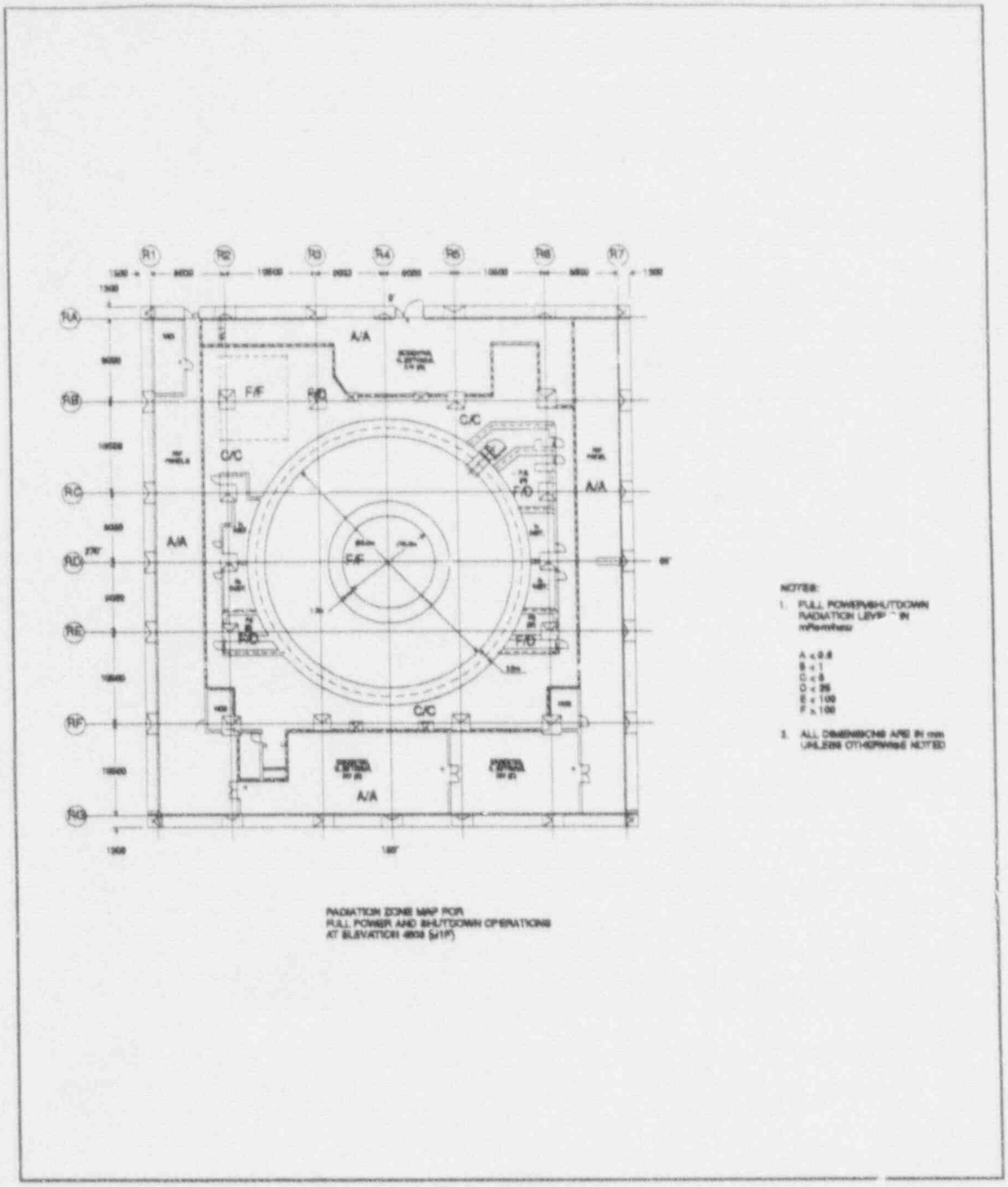
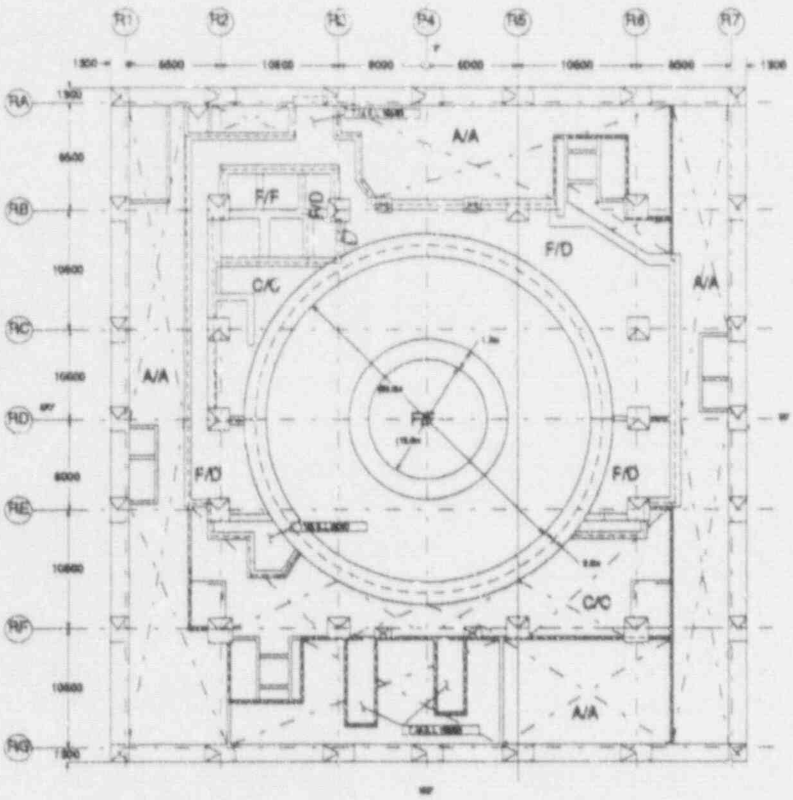


Figure 3.7d



R1
R2
R3
R4
R5
R6
R7
RA
RB
RC
RD
RE
RF
RG
A/A
F/F
R/D
C/C
C/C
F/D
A/A
A/A
F/F
F/D
C/C
A/A
NOTES:
1. FULL POWER/SHUTDOWN RADIATION LEVEL IN mRem/hour
A ≤ 0.5
B < 1
C < 5
D < 25
E < 100
F ≥ 100
2. ALL DIMENSIONS ARE IN mm UNLESS OTHERWISE NOTED
RADIATION ZONE MAP FOR
FULL POWER AND SHUTDOWN OPERATIONS

Figure 3.7e



NOTES:

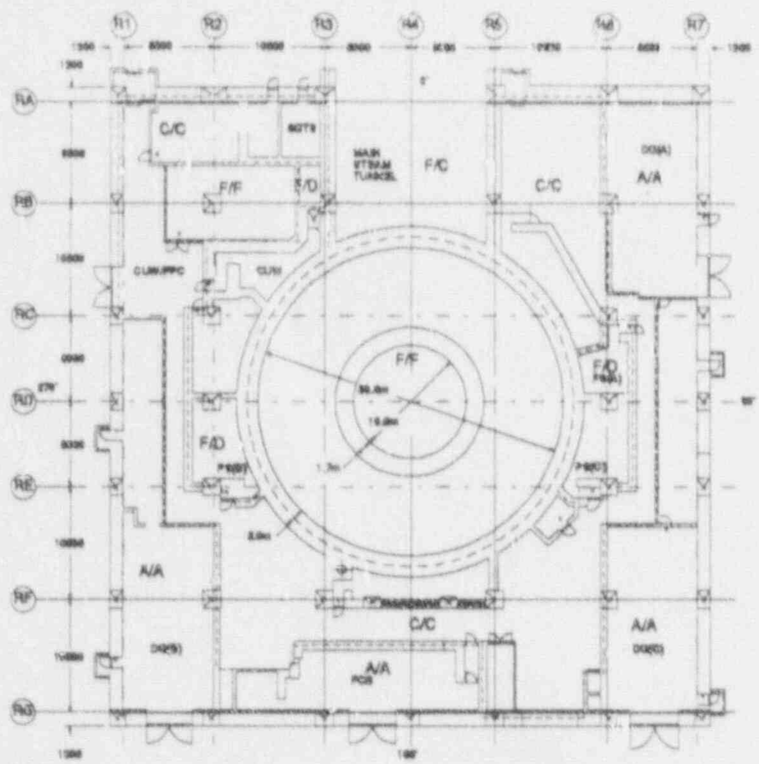
1. FULL POWER/SHUTDOWN RADIATION LEVELS IN mRem/hour

A ≤ 0.8
B < 1
C < 5
D < 25
E < 100
F > 100

2. ALL DIMENSIONS ARE IN mm UNLESS OTHERWISE NOTED

RADIATION ZONE MAP FOR
FULL POWER AND SHUTDOWN OPERATIONS
AT ELEVATION 8500

Figure 3.7f



NOTES:

1. FULL POWER/SHUTDOWN RADIATION LEVELS IN mRem/hour

   A < 0.6
   B < 1
   C < 5
   D < 25
   E < 100
   F ≥ 100

2. ALL DIMENSIONS ARE IN mm UNLESS OTHERWISE NOTED

RADIATION ZONE MAP FOR
FULL POWER AND SHUTDOWN OPERATIONS
AT ELEVATION 12300 (1F)

Figure 3.7g

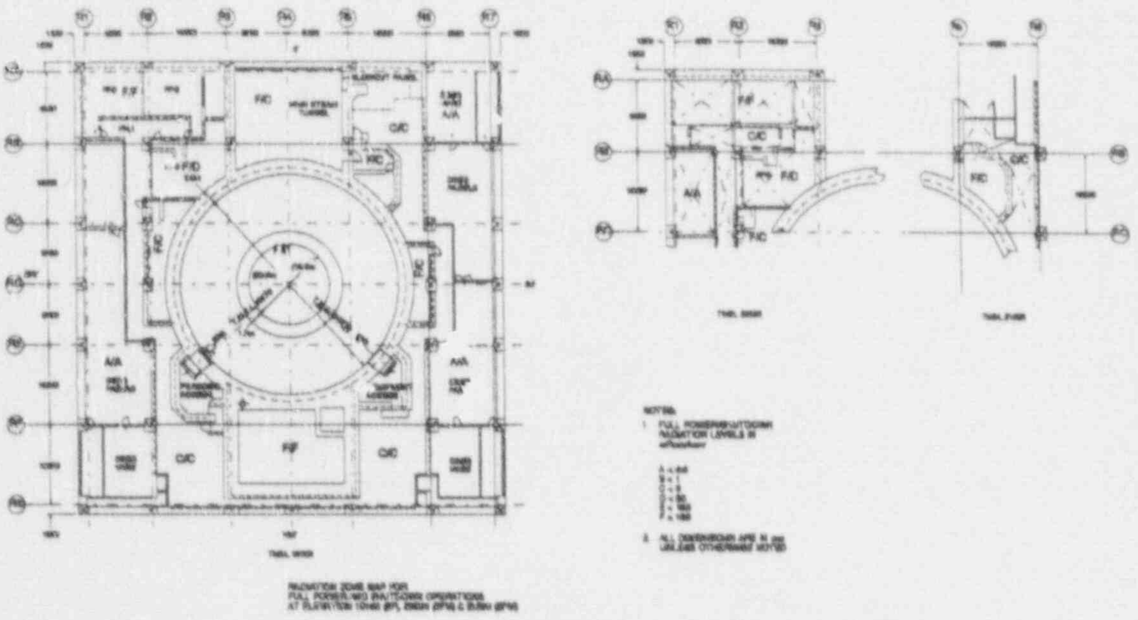
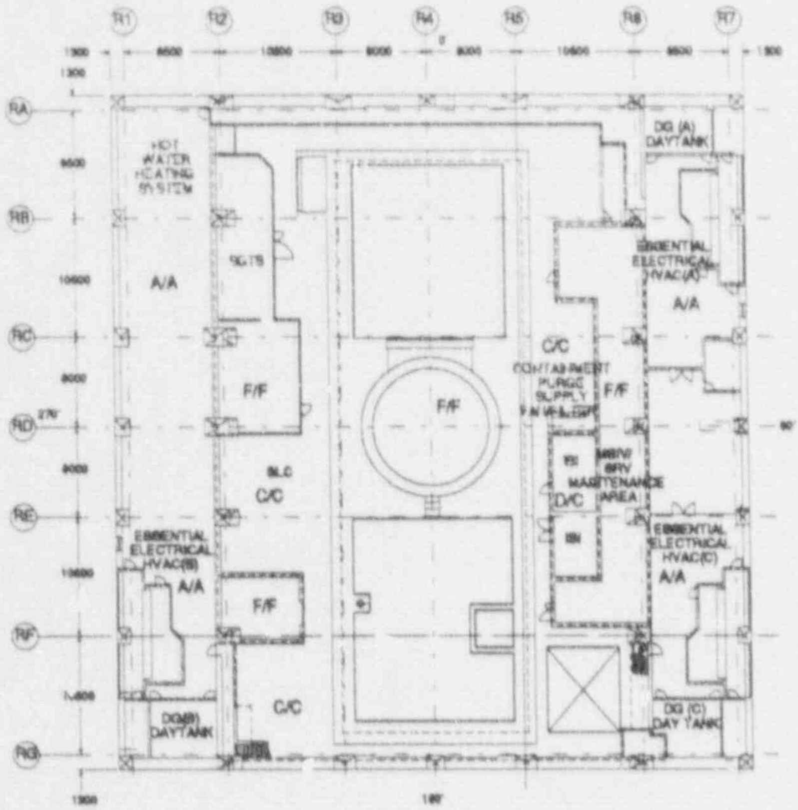


Figure 3.7h



NOTES:

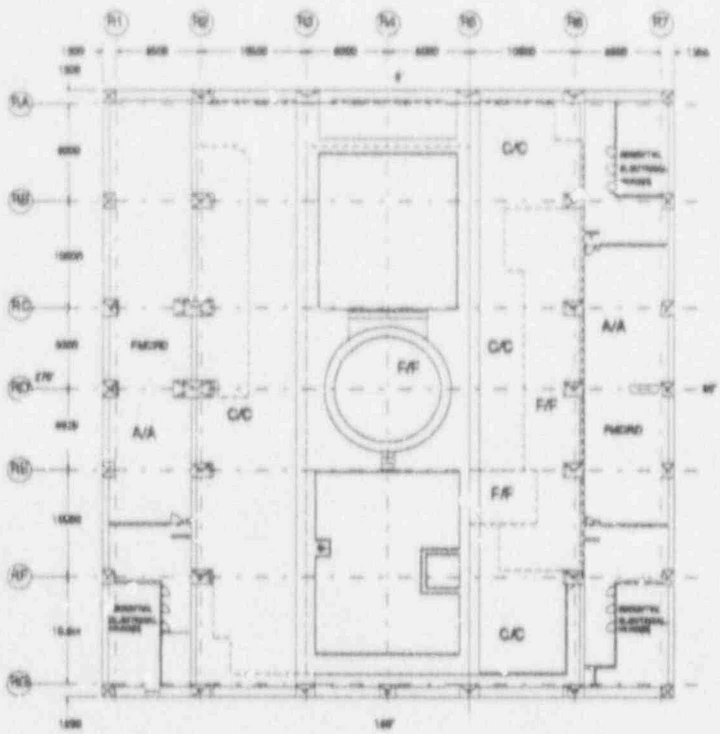
1. FULL POWER/SHUTDOWN RADIATION LEVELS IN mRem/hour

   A < 0.8
   B < 1
   C < 5
   D < 25
   E < 100
   F ≥ 100

2. ALL DIMENSIONS ARE IN mm UNLESS OTHERWISE NOTED.

RADIATION ZONE MAP FOR
FULL POWER AND SHUTDOWN OPERATIONS
AT ELEVATION 23500 (3F)

Figure 3.7i



NOTES

1. FULL POWER/SHUTDOWN RADIATION LEVELS IN mRem/hour

   A ≤ 0.5
   B < 1
   C < 5
   D < 50
   E < 100
   F ≥ 100

2. ALL DIMENSIONS ARE IN mm UNLESS OTHERWISE NOTED

RADIATION ZONE MAP FOR
FULL POWER AND SHUTDOWN OPERATIONS
AT ELEVATION 17300 (4F)

Figure 3.7j

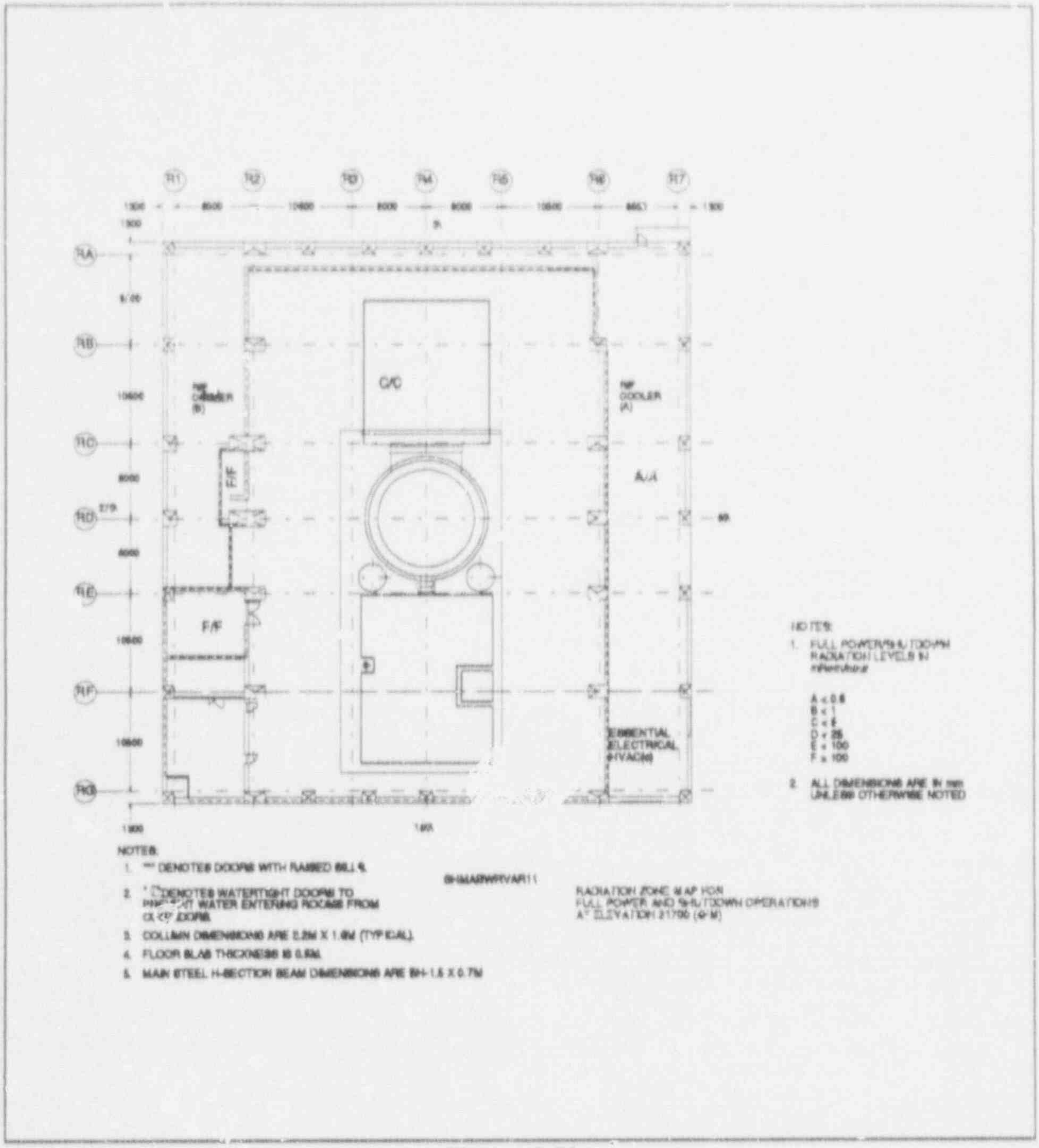

R1
R2
R3
R4
R5
R6
R7
RA
RB
RC
RD
RE
RF
RG
C/C
RIP COOLER (B)
RIP COOLER (A)
F/F
A/A
ESSENTIAL ELECTRICAL HVAC(A)
NOTES:
1. FULL POWER/SHUTDOWN RADIATION LEVELS IN mRem/hour
A < 0.6
B < 1
C < 5
D < 25
E < 100
F ≥ 100
2. ALL DIMENSIONS ARE IN mm UNLESS OTHERWISE NOTED
NOTES:
1. DENOTES DOORS WITH RAISED SILLS.
2. DENOTES WATERTIGHT DOORS TO PREVENT WATER ENTERING ROOMS FROM OTHER ROOMS
3. COLUMN DIMENSIONS ARE 2.2M X 1.8M (TYPICAL)
4. FLOOR SLAB THICKNESS IS 0.5M
5. MAIN STEEL H-SECTION BEAM DIMENSIONS ARE BH-1.5 X 0.7M
RADIATION ZONE MAP FOR FULL POWER AND SHUTDOWN OPERATIONS AT ELEVATION 21700 (4F M)

Figure 3.7k

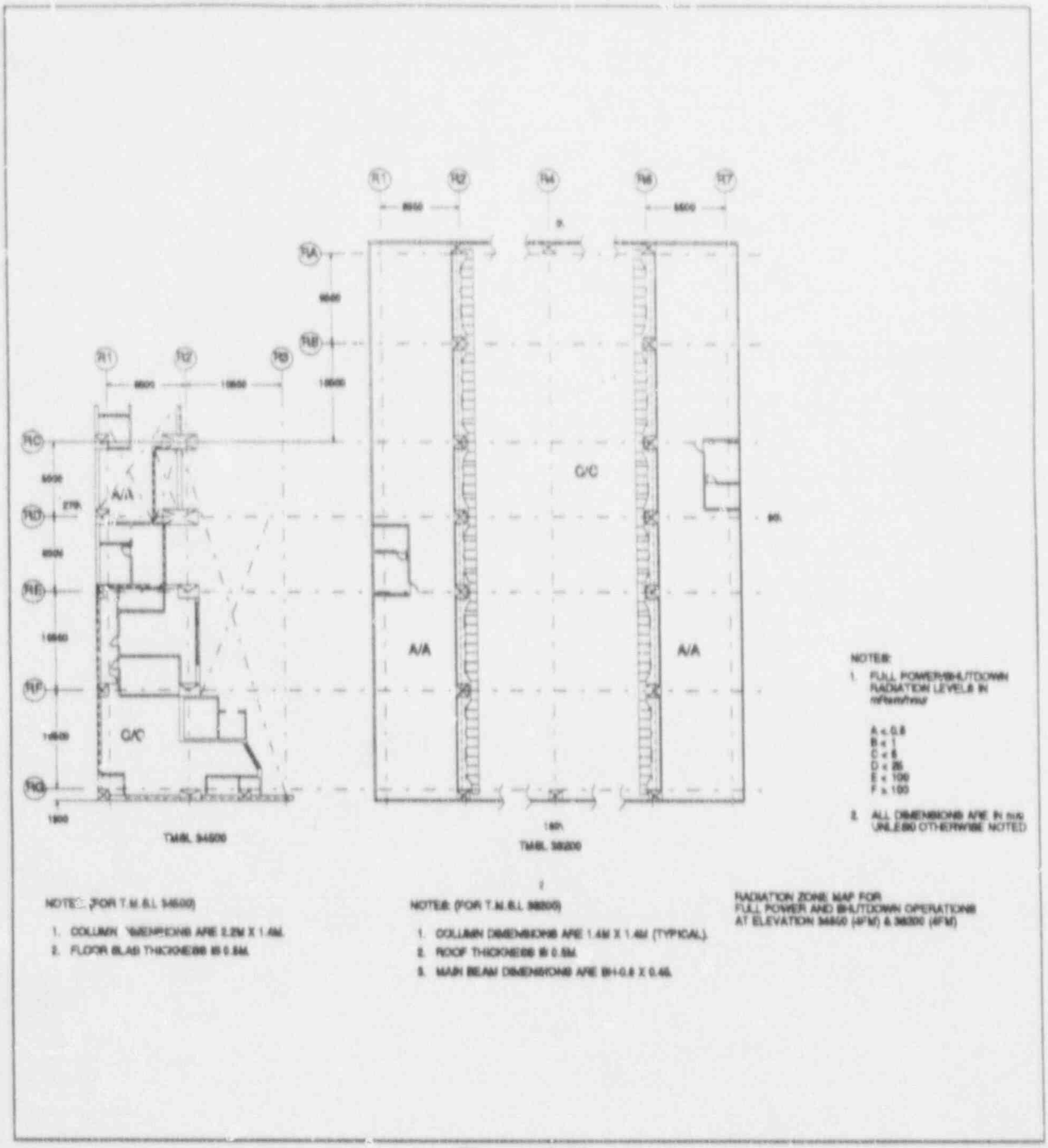
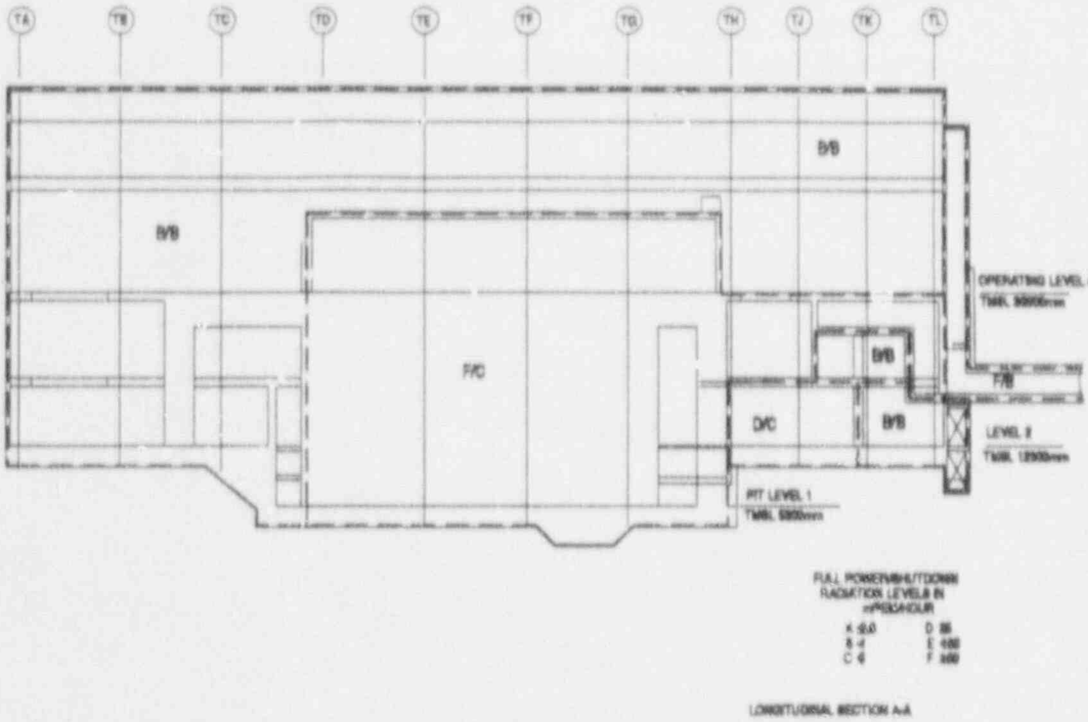

A/A
C/C
A/A
A/A
C/C
NOTES:
1. FULL POWER/SHUTDOWN RADIATION LEVELS IN mRem/hour
A < 0.5
B < 1
C < 5
D < 25
E < 100
F ≥ 100
2. ALL DIMENSIONS ARE IN mm UNLESS OTHERWISE NOTED
NOTES: (FOR T.M.S.L 34500)
1. COLUMN DIMENSIONS ARE 2.2M X 1.4M.
2. FLOOR SLAB THICKNESS IS 0.8M.
NOTES: (FOR T.M.S.L 38200)
1. COLUMN DIMENSIONS ARE 1.4M X 1.4M (TYPICAL).
2. ROOF THICKNESS IS 0.5M.
3. MAIN BEAM DIMENSIONS ARE BH-0.8 X 0.45.
RADIATION ZONE MAP FOR
FULL POWER AND SHUTDOWN OPERATIONS
AT ELEVATION 34500 (4FM) & 38200 (4FM)

Figure 3.7l



TA
TB
TC
TD
TE
TF
TG
TH
TJ
TK
TL
R/B
F/C
D/C
OPERATING LEVEL 4
LEVEL 2
PIT LEVEL 1
LONGITUDINAL SECTION A-A

Figure 3.7m

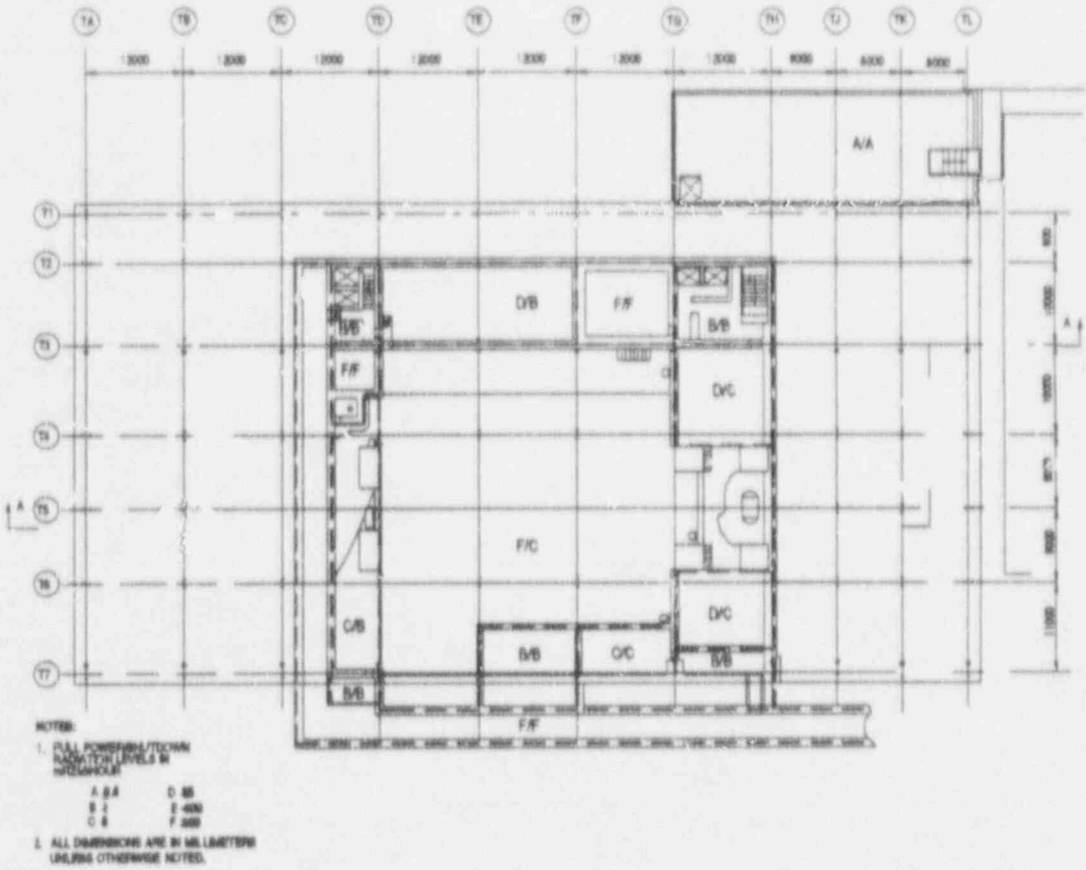
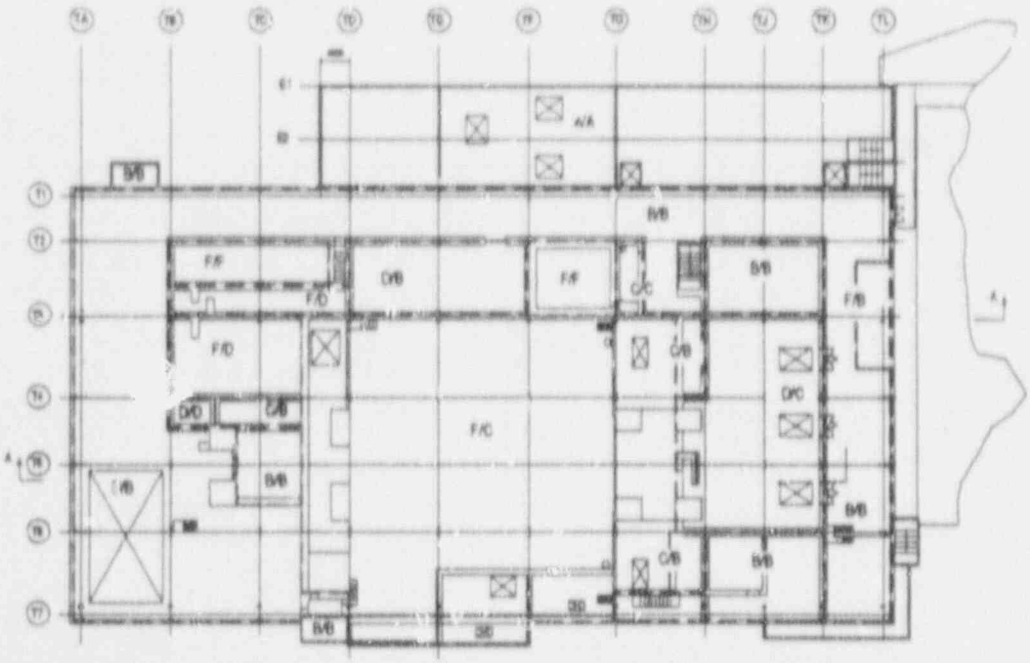


Figure 3.7n



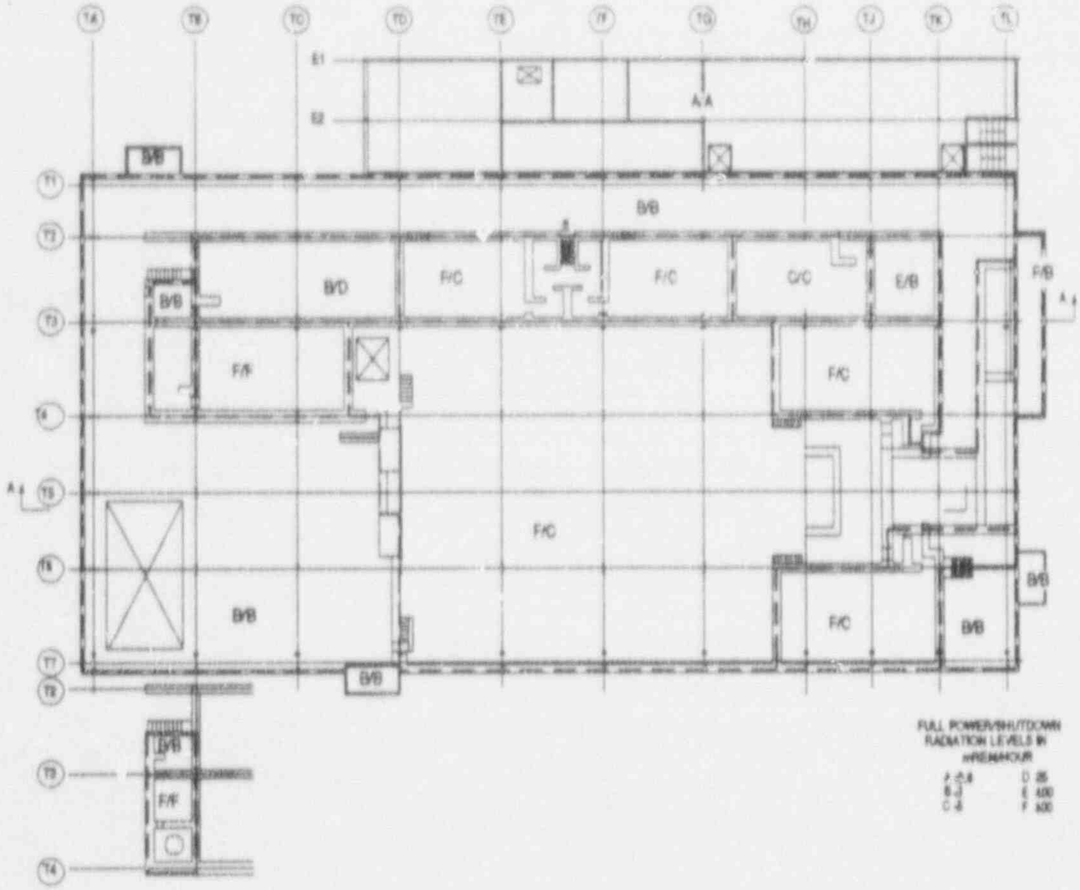
NOTES:

1. FULL POWER/SHUTDOWN RADIATION LEVELS IN mREM/HOUR

   A [illegible] D [illegible]
   B [illegible] E [illegible]
   C [illegible] F [illegible]

2. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED.

Figure 3.7o



TA
TB
TC
TD
TE
TF
TG
TH
TJ
TK
TL
E1
E2
A/A
T1
T2
T3
T5
T6
T7
T8
T9
B/B
B/D
F/C
C/C
E/B
F/B
F/F
FULL POWER/SHUTDOWN
RADIATION LEVELS IN
mREM/HOUR

Figure 3.7p

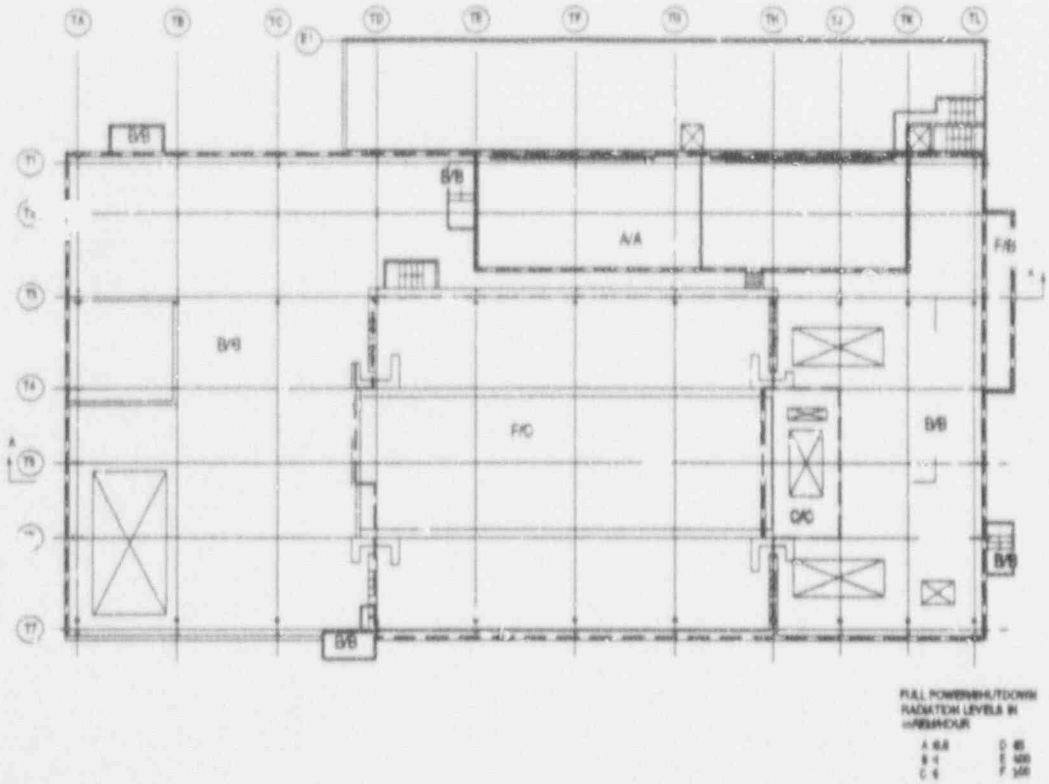
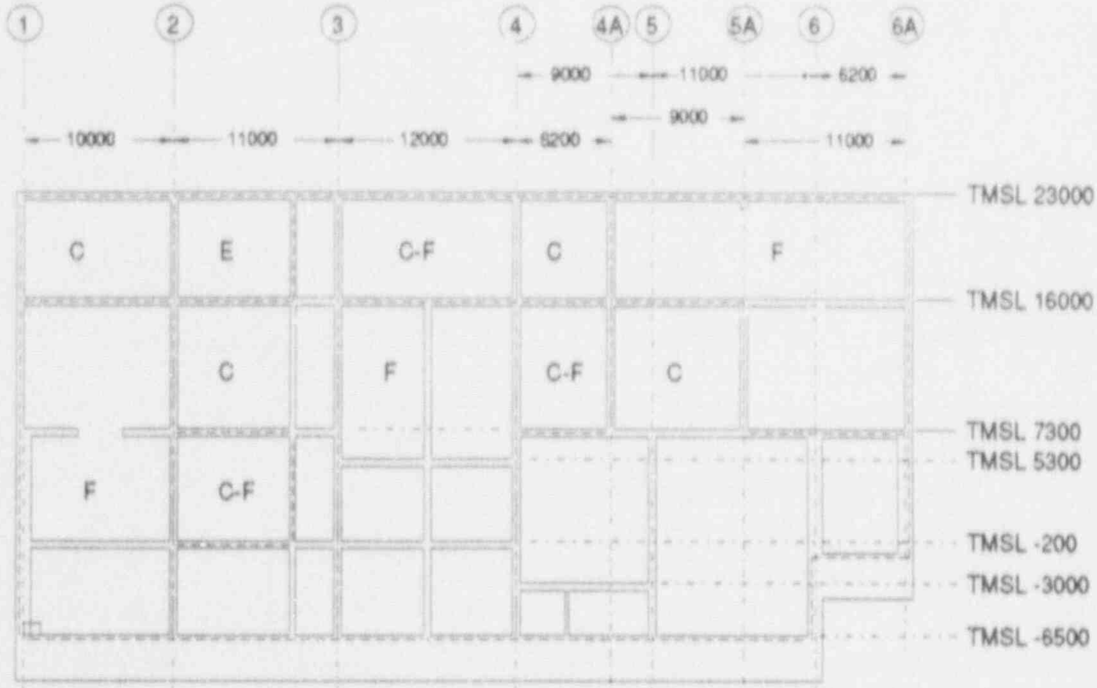


Figure 3.7q



NOTES:

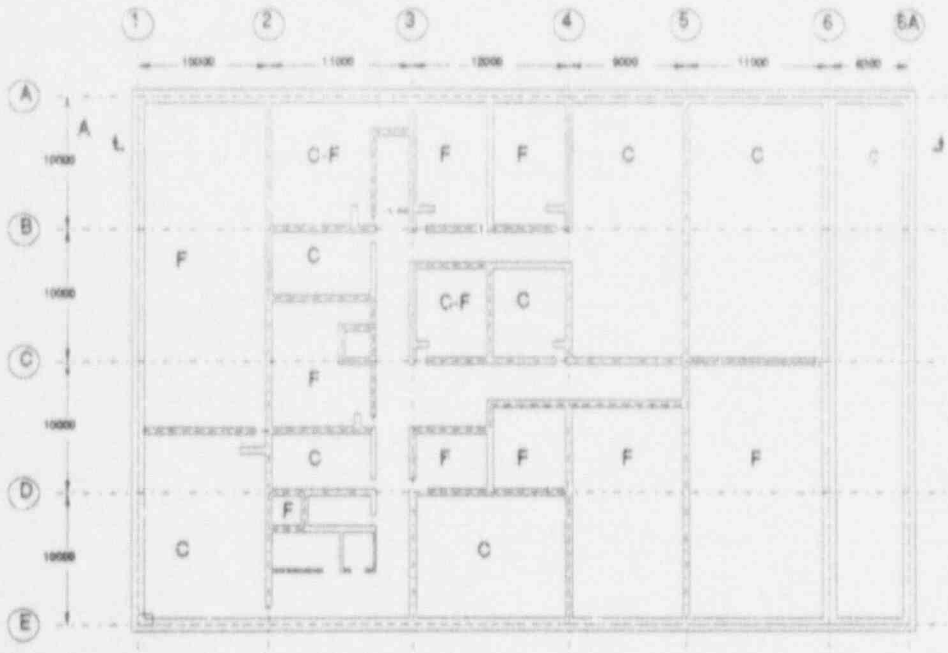
1. A ≤ 0.6mrem/hr D < 25.0mrem/hr
   B < 1.9mrem/hr E < 100mrem/hr
   C < 5.0mrem/hr F ≥ 100mrem/hr
2. ALL DIMENSIONS ARE IN MILLIMETER UNLESS OTHERWISE NOTED.

Figure 3.7r

NOTES:

1. A ≤ 0.6mrem/hr D < 25.0mrem/hr
   B < 1.0mrem/hr E < 100mrem/hr
   C < 5.0mrem/hr F ≥ 100mrem/hr
2. ALL DIMENSIONS ARE IN MILLIMETER UNLESS OTHERWISE NOTED.

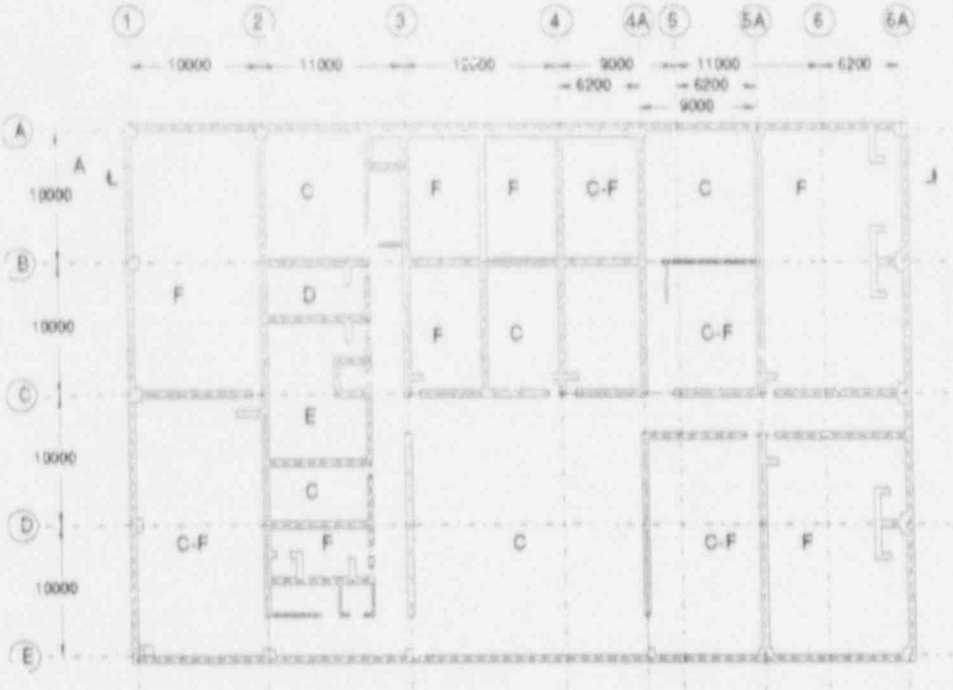
Figure 3.7s



NOTES:

1. A ≤ 0.5mrem/hr $\quad$ D < 25.0mrem/hr
   B < 1.0mrem/hr $\quad$ E < 100mrem/hr
   C < 5.0 mrem/hr $\quad$ F ≥ 100mrem/hr
2. ALL DIMENSIONS ARE IN MILLIMETER UNLESS OTHERWISE NOTED.

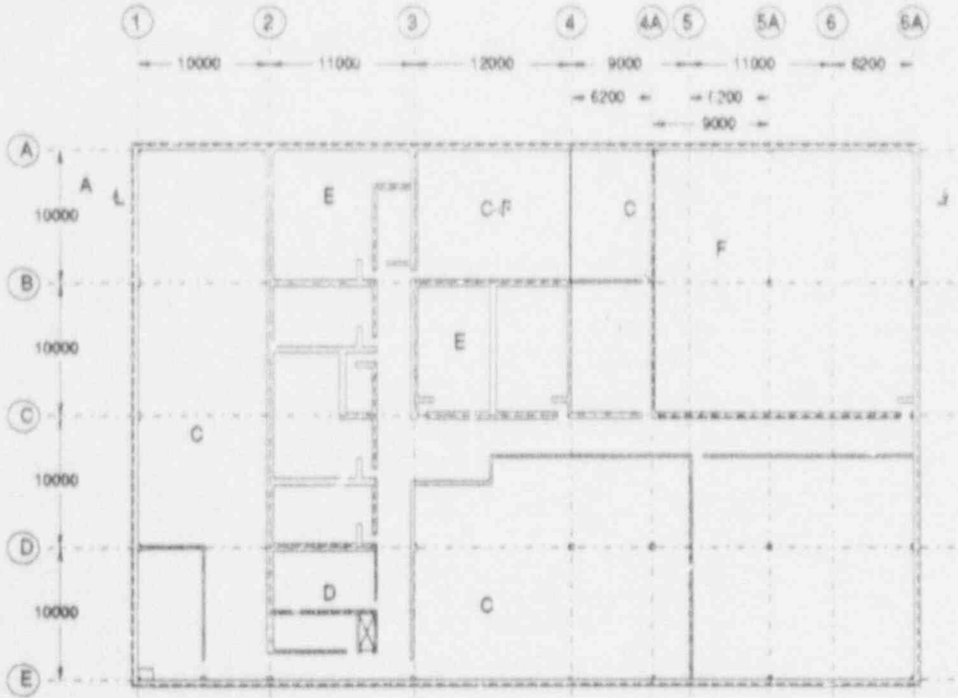
Figure 3.7t



NOTES:

1. A ≤ 0.6mrem/hr D < 25.0mrem/hr
   B < 1.0mrem/hr E < 100mrem/hr
   C < 5.0mrem/hr F ≥ 100mrem/hr
2. ALL DIMENSIONS ARE IN MILLIMETER UNLESS OTHERWISE NOTED.

Figure 3.7u



NOTES:

1. A ≤ 0.6mrem/hr   D < 25.0mrem/hr
   B < 1.0mrem/hr   E < 100mrem/hr
   C < 5.0mrem/hr   F ≥ 100mrem/hr
2. ALL DIMENSIONS ARE IN MILLIMETER UNLESS OTHERWISE NOTED.

Figure 3.7v

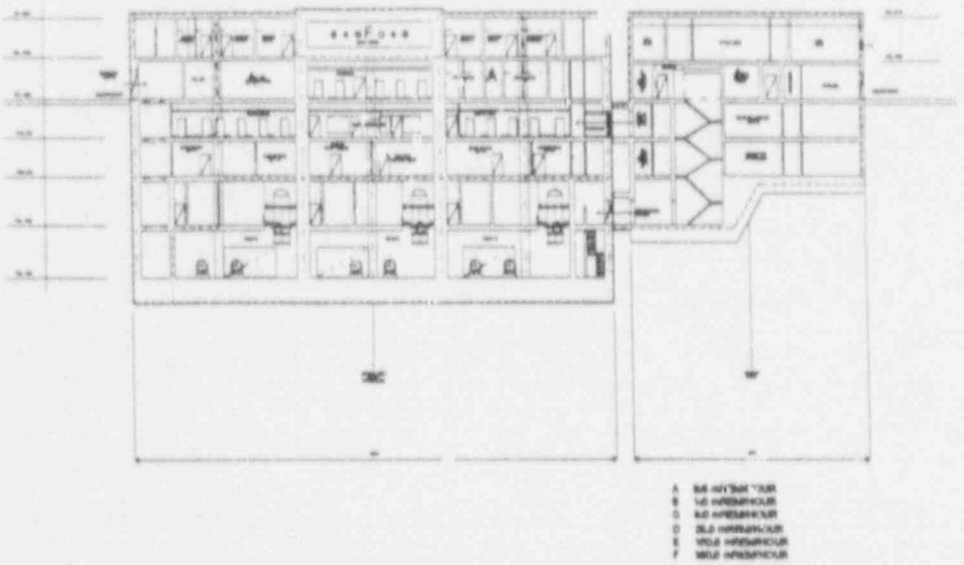


FIGURE 3.7w CONTROL BUILDING RADIATION ZONE, NORMAL OPERATION, SIDE VIEW

Figure 3.7w

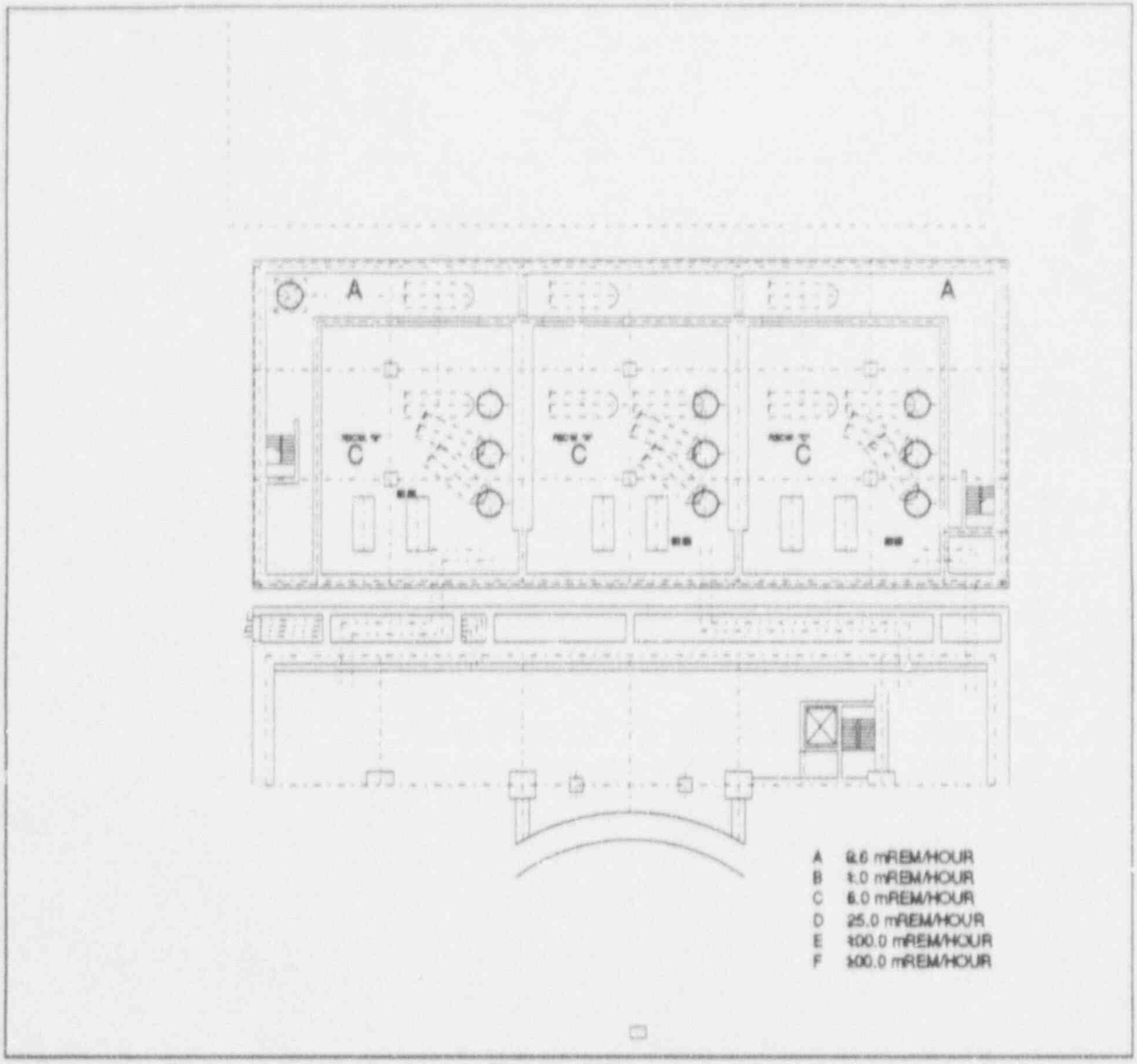

A
C
A 0.6 mREM/HOUR
B 1.0 mREM/HOUR
C 6.0 mREM/HOUR
D 25.0 mREM/HOUR
E 100.0 mREM/HOUR
F 100.0 mREM/HOUR

Figure 3.7x

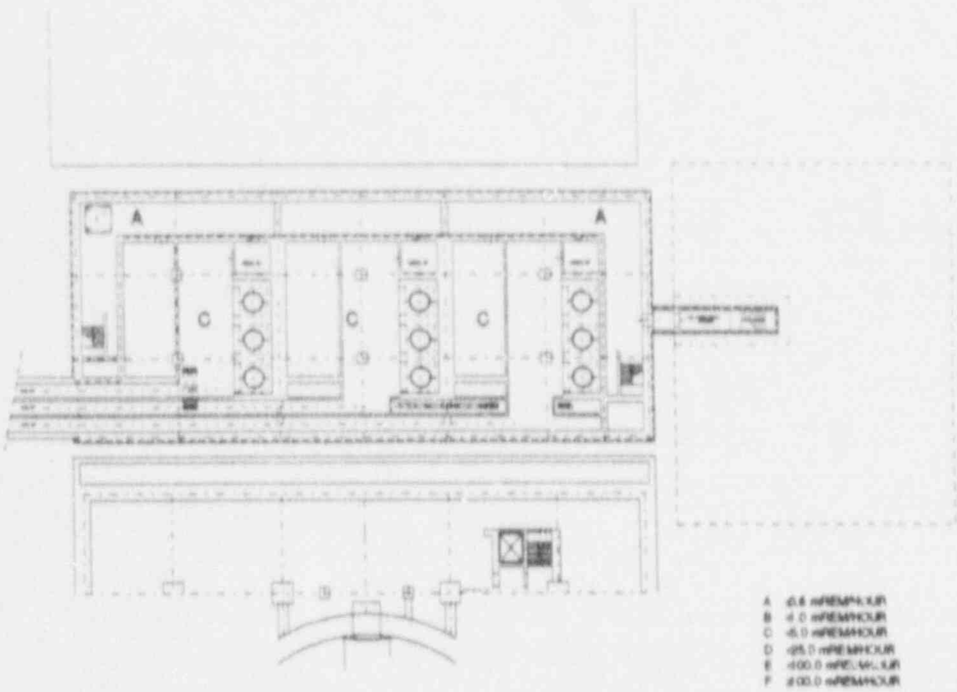

A
A
C
C
C
A <0.6 mREM/HOUR
B <1.0 mREM/HOUR
C <5.0 mREM/HOUR
D <25.0 mREM/HOUR
E <100.0 mREM/HOUR
F ≥100.0 mREM/HOUR

Figure 3.7y

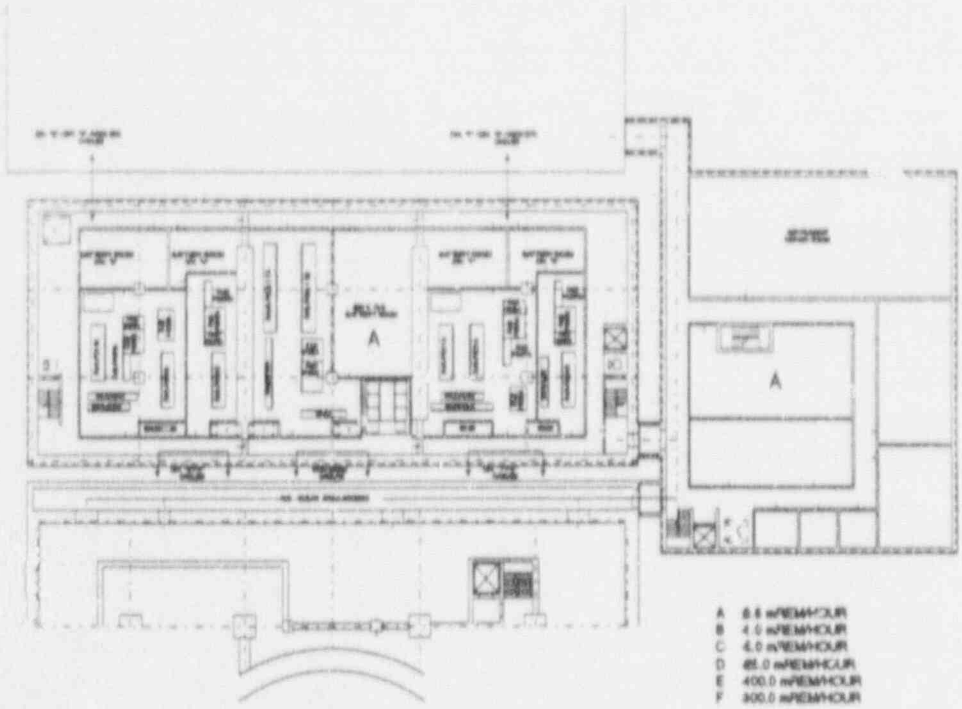


Figure 3.7z

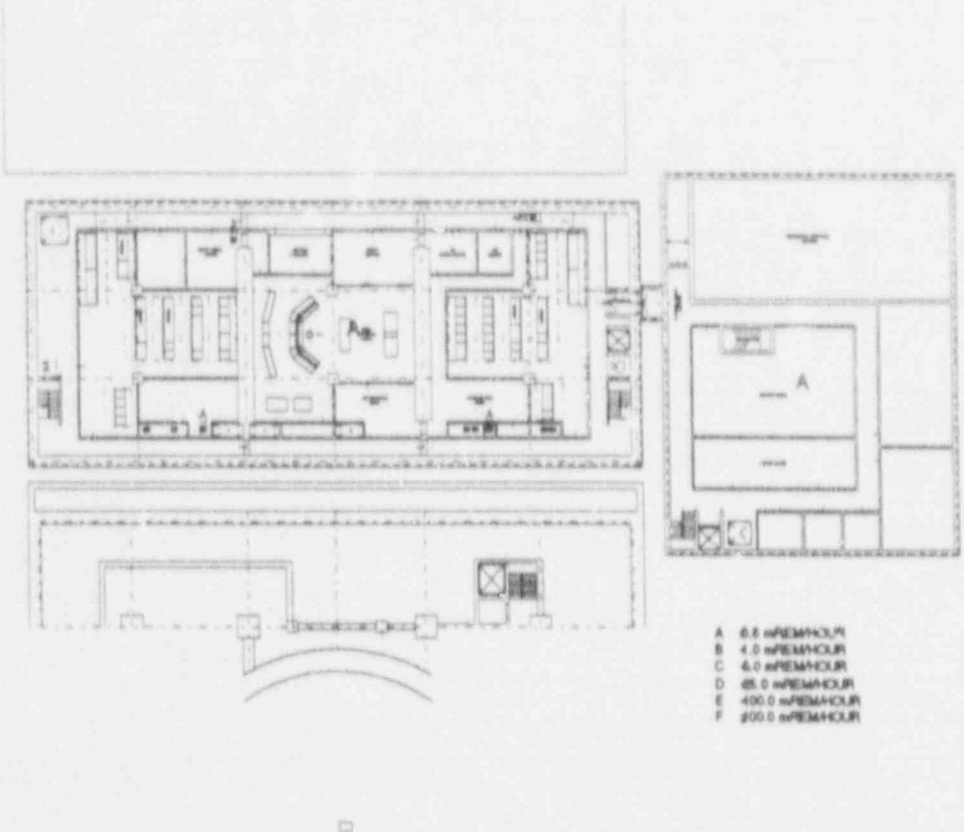

A 6.6 mREM/HOUR
B 4.0 mREM/HOUR
C 6.0 mREM/HOUR
D 65.0 mREM/HOUR
E 400.0 mREM/HOUR
F 800.0 mREM/HOUR
A

Figure 3.7aa

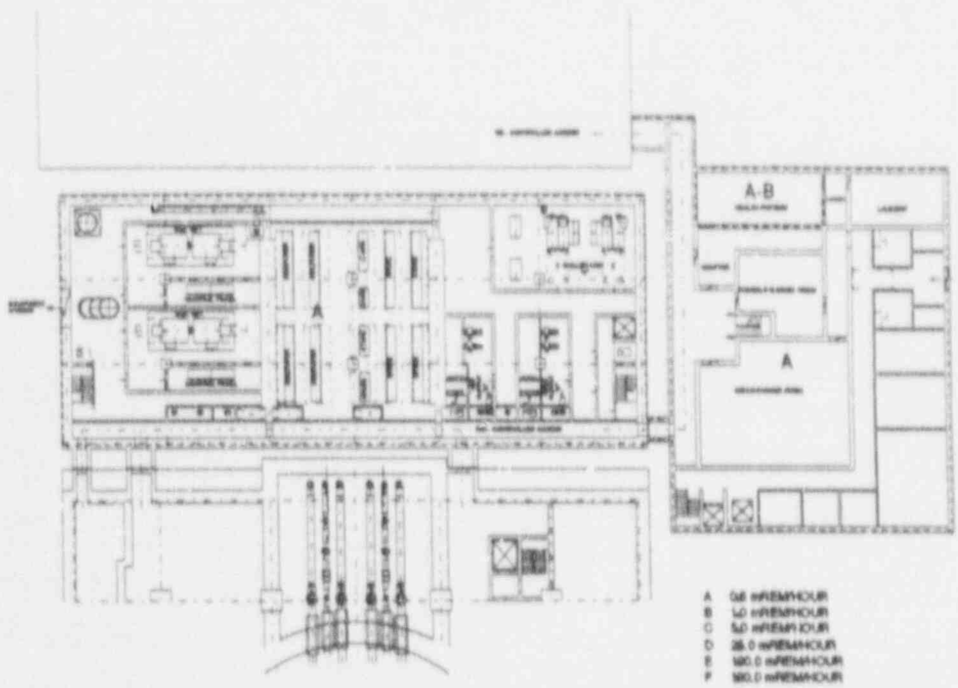


Figure 3.7bb

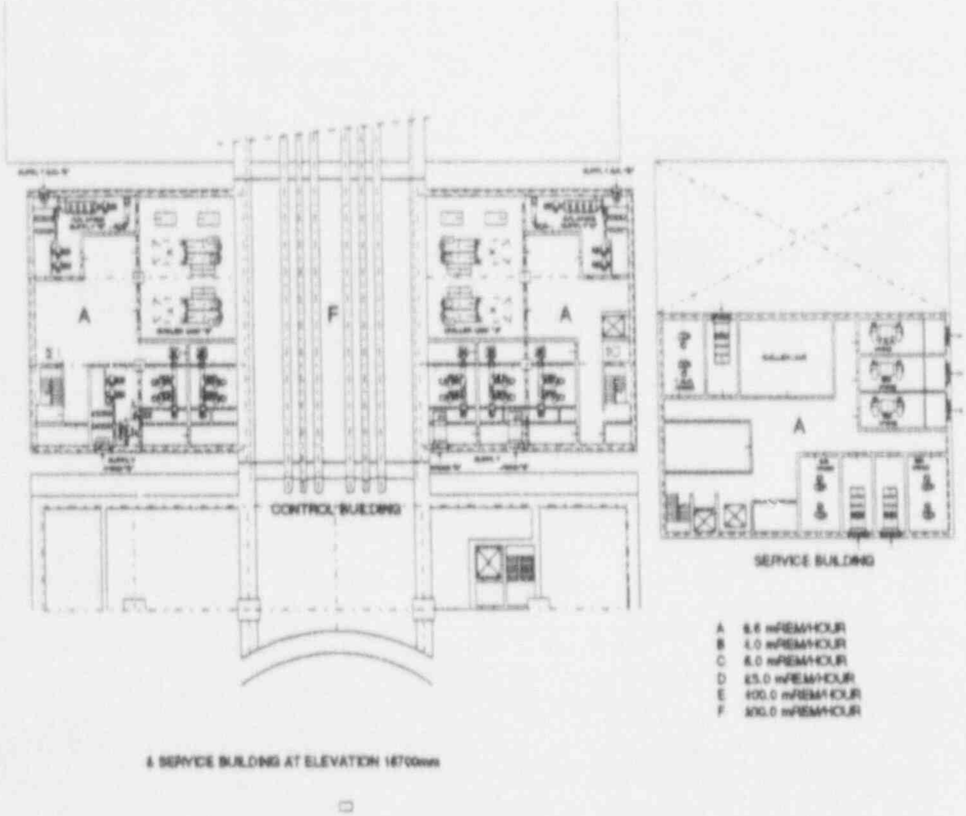

A
F
A
CONTROL BUILDING
A
SERVICE BUILDING
A 6.6 mREM/HOUR
B 4.0 mREM/HOUR
C 8.0 mREM/HOUR
D 25.0 mREM/HOUR
E 100.0 mREM/HOUR
F 200.0 mREM/HOUR
& SERVICE BUILDING AT ELEVATION 16700mm

Figure 3.7cc

3.8 Reliability Assurance Program

Applicants utilizing the design defined in this certification will perform a Reliability Assurance Program (RAP). The RAP will have the following two elements:

(1) A Design Reliability Assurance Program (D-RAP) and

(2) An Operational Reliability Assurance Program (O-RAP)

The O-RAP is related to plant operating issues and will track equipment reliability to demonstrate that the plant is being operated and maintained consistent with Probabilistic Risk Assessment (PRA) assumptions such that overall risk is not unknowingly degraded during plant operation. The O-RAP does not form part of this ABWR design certification and is not discussed further.

The following is a summary of the ABWR D-RAP.

Introduction

The ABWR Design Reliability Assurance Program (D-RAP) is a program that will be performed during the detailed design and equipment selection phases of a project to assure that the important ABWR reliability assumptions of the PRA will be considered throughout the plant life. The PRA evaluates plant response to initiating events to assure that plant damage has a very low probability and that risk to the public is very low. Input to the PRA includes details of the plant design and assumptions about the reliability of plant risk-significant structures, systems and components (SSCs) throughout plant life.

The D-RAP will include the design evaluation of ABWR and will identify relevant aspects of plant operation, maintenance, and performance monitoring of important plant SSCs for owner/operator consideration in assuring safety of the equipment and limited risk to the public. The policy and implementation procedures will be specified by the plant designer.

Scope

The ABWR D-RAP will include the future design evaluation of the ABWR, and it will identify relevant aspects of plant operation, maintenance, and performance monitoring of plant risk-significant SSCs. The PRA for the ABWR and other industry sources will be used to identify and prioritize those SSCs that are important to prevent or mitigate plant transients or other events that could present a risk to the public.

Purpose

The purpose of the D-RAP is to assure that plant safety as estimated by the PRA is maintained as the detailed design evolves through the implementation and procurement phases and pertinent information is provided in the design documentation to assure that equipment reliability, as it affects plant safety, can be maintained through operation and maintenance during the entire plant life.

Objective

The objective of the D-RAP is to identify those plant SSCs that are significant contributors to risk, as identified by the PRA or other sources, and to assure that, during the implementation phase, plant design continues to utilize risk-significant SSCs whose reliability is commensurate with the PRA assumptions. The D-RAP will also identify key assumptions regarding operation, maintenance and monitoring activities that the plant designer should consider in developing the O-RAP to assure that such SSCs can be expected to operate throughout plant life with reliability consistent with that assumed in the PRA.

Summary

This section represents a commitment that combined operating license applicants referencing the certified design will implement a D-RAP program that meets the objectives outlined above. There are no inspections, tests, analyses and acceptance criteria (ITAAC) specifically aimed at verifying implementation of the D-RAP commitment.

3.9 Welding

Design Description

Welds that perform the functions of fluid pressure boundary integrity or structural support functions will be made in strict compliance with the industrial Codes and Standards which have been developed to assure soundness and adequacy for the intended purpose.

The scope of this generic material is to address the full spectrum of welds in the facility, recognizing that different welds serve different functions, some more critical to plant operability and public safety than others. Each individual weld will be evaluated against these factors and will be assigned the appropriate level of documentation, in-process control, and subsequent examination and tests to make certain that it meets the applicable requirements. All records will be retained in retrievable, auditable files.

Inspections, Tests, Analyses and Acceptance Criteria

Table 3.9 provides a description of the inspections, tests, and analyses (together with associated acceptance criteria) which will be performed to demonstrate compliance with the appropriate quality factor for welds made in accordance with the certified design.

Table 3.9: Welding

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
All welding-related procedures will be performed in compliance with the applicable regulatory requirements and industrial standards. Each weldor family of welds will be evaluated with respect to its intended function in both normal operational conditions and those resulting from upset, faulted, and/or emergency conditions. These evaluations will take into consideration the materials involved, the anticipated environment, stresses, fatigue, irradiation levels, and all other pertinent factors. The Code or Standard which provides the necessary level of weld soundness and integrity will be selected and specified. In cases where the published requirements need to be augmented or amplified, this will be implemented by the creation and issue of application-specific process documents. Controls will be maintained to assure that only the proper type and quality level of weld is produced or provided at each location or in each component. Review and approval of designs, drawings, travellers, and other pre-production documents will be conducted to make certain that welds planned for each application are the welds that have been specified. Instructions and controls will be provided to disposition and/or correct welds which originally fail to pass any of the specified acceptance criteria. Records generated during the production of welds will be retained in retrievable, auditable files.	Documentation covering welding-related activities will be reviewed. This will include review of: - welding specifications for each form of weld, including the use of proper materials in each location - welding implementation procedures, including welder training and certification - inspection and deviation disposition reports - record retention procedures	It will be confirmed that facility welding is in compliance with the certified design commitments.

4.0 Interface Tier 1 Material

10 CFR Part 52 addresses the issue of interface requirements that must be met by those portions of the plant for which the design certification applicant does not seek certification. Part 52 stipulates that these requirements must be sufficiently detailed to allow completion of the final safety analysis as well as the design-specific probabilistic risk assessment called for by the regulations. In addition, the certification application must include conceptual design of the interfacing facility features that has sufficient detail to support review of the application. 10 CFR Part 52.47(a)(1)(viii) requires justification that interface requirements are verifiable through inspections, tests or analyses and that the method to be used for this verification be included as part of the ITAAC required by Paragraph (a)(1)(vi) of Part 52. The purpose of this section is to provide the necessary Tier 1 material for interface items. No Tier 1 treatment is proposed for the conceptual designs of portions of the plant not within the scope of design certification.

4.1 Ultimate Heat Sink

Design Description

The ultimate heat sink (UHS) is not within the scope of the certified design. It is intended that a specific UHS will be selected and designed for any facility which has adopted the certified design. This plant specific UHS will meet the interface requirements defined below.

Interface Requirements

The UHS provides sufficient cooling water to the Reactor Service Water (RSW) system to permit safe shutdown and cooldown of the unit and maintain the unit in a safe shutdown condition. The UHS is sized so that makeup water is not required for at least 30 days following an accident. During this period design basis temperature and water chemistry limits are not exceeded.

During normal plant operation, the UHS removes the heat load of the RSW system during all phases of plant operation.

The UHS can withstand the most severe natural phenomena or site-related event (e. g., SSE tornado, hurricane, flood, freezing, spraying, pipe whip, jet forces, missiles, fire, flooding as a result of pipe failures or transportation accident) and reasonably probable combinations of less severe phenomena and/or events, without impairing its safety function.

The safety related portions of the UHS can perform their required cooling function assuming a single active failure in any mechanical or electrical system. The safety related portions of the UHS are mechanically and electrically separated. The UHS can withstand any credible single failure of man-made structural features without impairing its safety function. The UHS and any pumps, valves, structures or other components that remove heat from safety systems shall be designed to Seismic Category I and ASME Code, Section III, Class 3, Quality Group C and applicable IEEE requirements.

Inspections, Tests, Analyses and Acceptance Criteria

Table 4.1 provides a definition of the inspections, tests, and/or analyses together with the associated acceptance criteria which will be used to verify that the UHS meets interface requirements.

Table 4.1: Ultimate Heat Sink System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. UHS can remove sufficient heat to permit safe shutdown and cooldown of the unit and maintain the unit in a safe shutdown condition.	1. The heat removal capability will be determined by a review of design and procurement documents.	1. Sufficient heat removal capacity provided.
2. Makeup water will not be required for at least 30 days following an accident.	2. The makeup requirements of the as-built facility will be evaluated by analysis and review of design documentation.	2. Makeup water is not required for at least 30 days following an accident.
3. UHS can remove the heat load of the RSW system during all phases of normal plant operation.	3. Heat removal capability of the as-built facility will be evaluated and compared to requirements.	3. Sufficient heat removal capacity provided.
4. UHS can withstand the most severe natural phenomena or site-related event and reasonably probable combinations of less severe phenomena and/or events without impairing its safety function.	4. A review of the as-built facility will be conducted.	4. Ability to withstand phenomena or events is confirmed.
5. Safety related portions of UHS are mechanically and electrically separated and can perform their safety related function assuming a single active failure in any mechanical or electrical system.	5. Separation features of the facility will be reviewed by inspection and analysis. Ability to function after any single active failure will be determined by analysis of the installed system.	5. Separation and ability to function after any single active failure confirmed.
6. UHS and any pumps, valves, structures, or other components that remove heat from safety systems are designed to codes and standards in the Design Description.	6. Adherence to codes and standards is determined by inspection of as built equipment documentation.	6. Adherence to codes and standards confirmed.

4.2 Offsite Power System

Design Description

The Offsite Power System is not within the scope of the certified design. However, any facility which utilizes the certified design must be coupled with an offsite power supply network that is compatible with the technical characteristics assumed in the certified design. These characteristics are summarized in the following interface requirements.

Interface Requirements

The site-specific interfacing Offsite Power System must meet interface requirements in the following areas. Entries in Table 4.2 define these requirements in more detail.

(1) availability of alternate sources of power

(2) voltage variations

(3) frequency variations

(4) reliability of offsite power

(5) independence and separation of main and reserve offsite circuits

(6) switching configurations

(7) main transformer configuration

(8) transformer design requirements

(9) fire protection aspects for transformer oil systems

(10) circuit breaker and switch design requirements

(11) synchronization capabilities

(12) protection circuit configurations

(13) DC power design requirements

(14) AC power (auxiliary loads) design requirements

(15) backup protection requirements

Inspections, Tests, Analyses and Acceptance Criteria

Table 4.2 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be used to verify that the Offsite Power Supply System meets interface requirements.

Table 4.2: Offsite Power System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. In cases of failure of the normal preferred power supply circuit, alternate preferred power should normally remain available to the reserve auxiliary transformer.	1. Inspection of the normal and alternate preferred power sources will be performed to confirm that they are supplied from different switching stations.	1. Inspection confirms that the normal and alternate preferred power sources are supplied from different switching stations.
2. The voltage variations of the offsite power feeders shall be no more than plus or minus 10 percent of their nominal value during steady state operation. There should be no more than a 20 percent voltage dip during motor starting.	2. Inspection of offsite power transmission system records will be performed to confirm nominal voltage variations do not exceed 10 percent of their nominal value during steady state operation and will support a voltage decrease of no more than 20 percent from nominal during motor starting.	2. Transmission system records confirm nominal voltage variations do not exceed 10 percent of their nominal value during steady state operation and will support a voltage decrease of no more than 20 percent from nominal during motor starting.
3. Normal steady state frequency of the power system shall be maintained within plus or minus 2 cycles of 60 cycles per second during recoverable periods of system instability.	3. Inspection of offsite power system records will be performed to confirm that frequency stability is within 2 cycles of the nominal 60 cycles per second.	3. Inspection of offsite power system records confirm that frequency stability is within 2 cycles of the nominal 60 cycles per second.
4. The site specific configuration of the incoming power lines shall be analyzed to assure that the expected availability of the offsite power is as good as the assumptions made in performing the plant probability risk analysis (PRA).	4. Analyses of the incoming power lines expected availability will be performed to confirm the assumptions made in the PRA.	4. Analyses of the incoming power lines expected availability confirms the assumptions made in the PRA.
5. The main and reserve offsite power systems shall be electrically independent and physically separated. They shall be connected to switching stations which are independent and separated and connected to different transmission systems.	5. Inspection of the main and reserve offsite power systems will be performed to confirm that they are electrically independent and physically separated and are connected to switching stations which are independent and separated and supplied from different transmission systems.	5. Inspection of the main and reserve offsite power systems confirms that they are electrically independent and physically separated and are connected to switching stations which are independent and separated and supplied from different transmission systems.

Table 4.2: Offsite Power System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. The switching station to which the main offsite power circuit is connected shall have at least two full capacity main buses arranged such that: a. Any incoming or outgoing transmission line can be switched without affecting another line; b. Any single circuit breaker can be isolated for maintenance without interrupting service to any circuit; c. Faults of a single main bus are isolated without interrupting service to any circuit.	6. Inspection of the main offsite power circuit configuration and capacity will be performed to confirm the ability to switch incoming or outgoing transmission lines, isolate any single circuit breaker for maintenance, and isolate faults of a single main bus without affecting the other transmission lines or interrupting service to any circuit.	6. Inspection of the main offsite power circuit configuration and capacity confirms the ability to switch incoming or outgoing transmission lines, isolate any single circuit breaker for maintenance, and isolate faults of a single main bus without affecting the other transmission lines or interrupting service to any circuit.
7. The main power transformer shall be three normally energized, single-phase transformers with an additional installed spare. Provisions shall be made to permit connecting and energizing the installed spare in no more than 12 hours following the failure of one of the normally energized transformers	7. Inspection of the main power transformer will be performed to confirm that it consists of three normally energized, single-phase transformers with an additional installed spare and that provisions are made to permit connecting and energizing the installed spare in no more than 12 hours.	7. Inspection of the main power transformer confirms that it consists of three normally energized, single-phase transformers with an additional installed spare and that provisions are made to permit connecting and energizing the installed spare in no more than 12 hours.
8. The main power transformer shall be designed to meet the requirements of ANSI Standard C57.1200, General Requirements for Liquid-Immersed Distribution, Power and Regulating Transformers.	8. Inspection of the vendor as-built documentation will be performed to confirm that ANSI Standard C57.1200, General Requirements for Liquid-Immersed Distribution, Power and Regulating Transformers, was utilized in the design of the main power transformer.	8. Inspection of the vendor as-built documentation confirms that ANSI Standard C57.1200, General Requirements for Liquid-Immersed Distribution, Power and Regulating Transformers, was utilized in the design of the main power transformer.

Table 4.2: Offsite Power System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9. The main power transformer shall be 1500 MVA at a power factor of .9 and a nominal secondary winding voltage of 26 KV plus or minus 10 percent. Sufficient main power transformer and high voltage circuit impedance shall be provided to limit maximum available fault currents.	9. Inspection of the main power transformer nameplate ratings will be performed to confirm that the transformer rating is 1500 MVA at a power factor of .9 and a nominal secondary winding voltage of 26 KV plus or minus 10 percent. Analyses will be performed to determine the value of the possible fault currents and that sufficient main power transformer and high voltage circuit impedance is provided to limit maximum available fault currents.	9. Inspection of the main power transformer nameplate ratings confirms that the transformer rating is 1500 MVA at a power factor of .9 and a nominal secondary winding voltage of 26 KV. Analyses confirms that sufficient main power transformer and high voltage circuit impedance will provided to limit maximum available fault currents.
10. Physical separation between transformers and oil collection shall meet the following fire protection requirements: a. Shadow type fire walls or at least 50 feet of separation shall be provided between the main and the unit auxiliary transformers and between any two unit auxiliary transformers; b. 50 feet of separation Shall be provided between the main power and unit auxiliary transformers and the reserve auxiliary transformer; c. Oil collection pits shall be provided for the outdoor transformers.	10. Inspection will be performed to confirm that shadow type fire walls or at least 50 feet of separation has been provided between the main and the unit auxiliary transformers and between any two unit auxiliary transformers, 50 feet of separation has been provided between the main power and unit auxiliary transformers and the reserve auxiliary transformer, and oil collection pits have been provided for the outdoor transformers.	10. Inspection confirms that shadow type fire walls or at least 50 feet of separation has been provided between the main and the unit auxiliary transformers and between any two unit auxiliary transformers, 50 feet of separation has been provided between the main power and unit auxiliary transformers and the reserve auxiliary transformer, and oil collection pits have been provided for the outdoor transformers.
11. Circuit breakers and disconnect switches shall be sized and designed in accordance with the latest revision of ANSI Standard C37.06, Preferred Ratings and Related Capabilities for AC High-Voltage Circuit Breakers on a Symmetrical Current Basis.	11. Inspection of the circuit breakers and disconnect switches vendor documentation will be performed to confirm that they are sized and designed in accordance with the latest revision of ANSI Standard C37.06, Preferred Ratings and Related Capabilities for AC High-Voltage Circuit Breakers on a Symmetrical Current Basis.	11. Inspection of the circuit breakers and disconnect switches vendor documentation confirms that they are sized and designed in accordance with the latest revision of ANSI Standard C37.06, Preferred Ratings and Related Capabilities for AC High-Voltage Circuit Breakers on a Symmetrical Current Basis.

Table 4.2: Offsite Power System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
12. Although unit synchronization is normally through the main generator circuit breaker, provisions shall be made to synchronize the unit through the switching station's circuit breakers. This makes it possible to re-synchronize with the system following a load rejection within the steam bypass capability of the generating unit.	12. Inspection will be performed to confirm that provisions are made to synchronize the unit through the switching station's circuit breakers.	12. Inspection confirms that provisions are made to synchronize the unit through the switching station's circuit breakers.
13. All relay schemes used for protection of the offsite power circuits and the switching station's equipment shall be redundant and include backup protection features. All breakers shall be equipped with dual trip coils. Each redundant protection circuit which supplies a trip signal shall be connected to a separate trip coil. All equipment and cabling associated with each redundant system shall be physically separated.	13. Inspection will be performed to confirm that offsite power circuit breakers are provided with redundant and separated relay schemes, trip coils, cabling, and power supplies.	13. Inspection confirms that offsite power circuit breakers are provided with redundant and separated relay schemes, trip coils, cabling, and power supplies.
14. The DC power needed to operate redundant protection and control equipment of the offsite power system shall be supplied from two separate, dedicated switchyard batteries, each with a battery charger supplied from a separate AC bus. Each battery shall be capable of supplying the DC power required for normal operation of the switching station's equipment.	14. Inspection will be performed to confirm that redundant protection and control equipment of the offsite power system are powered from two redundant, separate, dedicated switchyard batteries capable of supplying the DC power required for normal operation of the switching station's equipment and each battery is provided with a battery charger supplied from a separate AC bus.	14. Inspection confirms that redundant protection and control equipment of the offsite power system are powered from two redundant, separate, dedicated switchyard batteries capable of supplying the DC power required for normal operation of the switching station's equipment and each battery is provided with a battery charger supplied from a separate AC bus.

Table 4.2: Offsite Power System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
15. Two low voltage power supply systems shall be provided to supply AC power to the switching station's auxiliary loads. Each system shall be supplied from separate, independent buses. The capacity of each system shall be adequate to meet the AC power requirements for normal operation of the switching station's equipment.	15. Inspection will be performed to confirm that switching station auxiliary loads are powered from redundant low voltage AC sources with the capacity to meet the AC power requirements for normal operation of the switching station's equipment.	15. Inspection confirms that switching station auxiliary loads are powered from redundant low voltage AC sources with the capacity to meet the AC power requirements for normal operation of the switching station's equipment.
16. Each transformer shall have primary and backup protective devices. DC power to the primary and backup protective devices shall be supplied from separate DC sources.	16. Inspection will be performed to confirm that each transformer contains primary and backup protective devices and DC power to the primary and backup protective devices are supplied from separate DC sources.	16. Inspection confirms that each transformer contains primary and backup protective devices and DC power to the primary and backup protective devices are supplied from separate DC sources.
17. The requirements of IEEE Standard 765, Preferred Power Supply for Nuclear Generating Stations, including NRC approved modifications, shall be met.	17. Inspection of the preferred power supply system will be performed to confirm that the requirements of IEEE Standard 765, Preferred Power Supply for Nuclear Generating Stations, including NRC approved modifications, are met.	17. Inspection of the preferred power supply system confirms that the requirements of IEEE Standard 765, Preferred Power Supply for Nuclear Generating Stations, including NRC approved modifications, are met.

4.3 Potable and Sanitary Water System

Design Description

The Potable and Sanitary Water (PSW) System is not within the scope of the certified design. It is intended that a specific PSW will be designed for any facility which has adopted the certified design. This plant specific PSW will meet the interface requirements defined below.

Interface Requirements

The PSW is designed to provide a minimum of 200 gpm of potable water during peak demand periods. Potable water is filtered and treated to prevent harmful physiological effects of plant personnel.

The PSW includes a sanitary drainage system which is designed to collect liquid wastes and entrained solids discharged by all plumbing fixtures located in areas with no sources of potentially radioactive wastes and conveys them to a sewage treatment facility. The sewage treatment facility treats sanitary waste at a range between 12,000 gpd and 48,800 gpd.

Inspections, Tests, Analyses and Acceptance Criteria

Table 4.3 provides a definition of the inspections, tests and/or analyses together with the associated acceptance criteria which will be used to verify that the PSW meets interface requirements.

Table 4.3: Potable and Sanitary Water System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The PSW can provide a minimum of 200 gpm of potable water during peak demand periods.	1. The as-built production capacity shall be determined by test.	1. The as-built production capacity is 200 gpm or more.
2. The sanitary drainage system collects wastes only from areas with no sources of potentially radioactive wastes.	2. The as-built sanitary drainage system shall be inspected to show that wastes are collected from areas with no sources of potentially radioactive wastes.	2. The as-built system is not connected to any areas with sources of potentially radioactive wastes.
3. The sewage treatment system has the capability of receiving waste at a rate between 12,000 gpd and 48,800 gpd.	3. The as-built sewage treatment system receiving capacity shall be determined by test or test and analyses if sufficient flow is not available.	3. The as-built receiving capacity is between 12,000 gpd and 48,800 gpd.

4.4 Turbine Service Water System

Design Description

Only the portion of the turbine service water system that is within the boundary of the turbine building is within the scope of the certified design. The remaining portions of the system are not within the certification scope and will be designed on a site-specific basis. Section 2.11.10, Turbine Service Water System, provides the description of the system that is within the certified design scope and identifies interface requirements on the portion of the system that is not within scope. The section also includes a definition of inspections, tests, analyses and acceptance criteria for verifying the in-scope portion of the system complies with the certified design and the site specific design meets interface requirements.

Inspections, Tests, Analyses and Acceptance Criteria

See Section 2.11.10.

4.5 Reactor Service Water System

The portion of the Reactor Service Water System (RSW) associated with taking the pump suction supply from the plant Ultimate Heat Sink (UHS) is not within the scope of the certified design. These features are dependent upon the UHS characteristics and will be designed on a site specific basis. Section 2.11.9 describes the configuration of the RSW that is within the certification scope and also identifies the interface requirements to be met by the out-of-scope portion of the system. In addition, Section 2.11.9 defines the inspection, tests analyses, and acceptance criteria for the in-scope design and the interface requirements.

Inspections, Tests, Analyses and Acceptance Criteria

See Section 2.11.9.

4.6 Makeup Water Preparation System

Design Description

The Makeup Water Preparation (MWP) System is not within the scope of the certified design. It is intended that a specific MWP System will be designed for any facility which has adopted the certified design. This plant specific MWP System will meet the interface requirements defined below.

Interface Requirements

The MWP system shall have two divisions capable of producing at least 200 gpm of demineralized water each. Storage of demineralized water shall be at least 200,000 gallons. Demineralized water shall be supplied to the Makeup Water Purified (MUWP) System at a minimum flow rate of approximately 600 gpm at a temperature between 50 to 100°F.

The MWP System is not connected to any systems having the potential for containing radioactive material.

The MWP System provides at least 200 gpm of filtered water to meet maximum anticipated peak demand periods for the Potable and Sanitary Water System.

Inspection, Test, Analyses and Acceptance Criteria

Table 4.6 provides a definition of the inspections, test, and/or analyses together with the associated acceptance criteria which will be used to verify that the MWP System meets interface requirements

Table 4.6: Makeup Water Preparation System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The MWP System shall be capable of producing at least 400 gpm of demineralized water.	1. The as-built MWP System shall be tested to determine its production capacity.	1. The production capacity of the as-built MWP System is at least 400 gpm.
2. The MWP System shall be capable of providing demineralized water to the MUWP system at a minimum flow of approximately 600 gpm at a temperature between 50 to 100°F.	2. The as-built MWP System shall be tested to determine the flow it can provide to the MUWP System and tested to determine the temperature of the water.	2. The supply capacity of the as-built MWP System shall be approximately 600 gpm at a temperature between 50 to 100°F.
3. The MWP System shall not be connected to any systems having the potential for containing radioactive material	3. The as-built MWP System shall be inspected to determine if it is connected to any potentially radioactive systems.	3. The as-built MWP System is not connected to any systems that may contain radioactive material.
4. The MWP System shall be capable of providing at least 200 gpm of filtered water to the PSW system to meet maximum peak demands.	4. The as-built MWP System shall be tested to determine if it can provide at least 200 gpm of filtered water to the PSW System for short periods.	4. The as-built MWP System is capable of providing at least 200 gpm of filtered water to the PSW System for short periods.

4.7 Communication System

Design Description

Section 2.12.17 of the Tier 1 system entries addesses those portions of the Communication System which are within the scope of the certified design. All other communication system elements (i.e., independent emergency communication, wireless communication, telephone, and portable sound-powered telephone handsets) are not within the design certification scope and will not be provided as part of the site-specific design.

Interface Requirements

No specific technical interface requirements have been identified for those portions of the plant communication system which are not within the scope of the certified design.

Inspections, Tests, Analyses and Acceptance Criteria

Because no interface requirements have been identified, there are no interface related inspections, tests, analyses and acceptance criteria as called for by 10 CFR Part 52.47 (a) (viii).

4.8 Airborne Particulate Radiation Monitoring

Monitoring of radiation areas in the plant are performed with a variety of instruments to measure both contained (in equipment) and uncontained (external contamination and airborne species) radiation sources. This equipment is within the scope of the certified design and is addressed in Sections 2.3.1 and 2.3.2. However, instrumentation to measure the airborne concentration of particulate radionuclides for determination of acceptable airborne contamination levels with respect to 10CFR20 are not within the scope of the current design basis. Such instrumentation will be provided on a site-specific basis and will be designed to meet the interface requirements set forth in Section 3.7B, paragraph 2.

4.9 Site Security

Design Description

In addition to personnel-based activities (guards), site security is supported by a variety of design features. Some of these features are within the scope of the certified design and these are addressed in Sections 2.16.3 and 2.12.18. In addition, there will be a security fence at the site boundary which will be supplied on a site-specific basis.

Interface Requirements — None identified.

Inspections, Tests, Analyses and Acceptance Criteria

No entries for this system.

5.0 Site Parameters

10 CFR Part 52.47(a)(iii) requires that the application for design certification include site parameters postulated for the design. The regulations also call for an analysis and evaluation of the design in terms of these parameters. The intent of this section is to provide Tier 1 material that complies with the requirements to define the site parameter postulated for the design.

Since it is intended the certified ABWR design be referenceable for a wide range of sites, it has been necessary to specify a set of site parameters enveloping the conditions which will occur at most potential power plant sites in the United States. These parameters are defined in Table 5.0. It is intended that any facility which references the certified design will utilize a site where the actual site-specific conditions are within the defined envelope.

In the case of seismic design parameters, deviations from the defined conditions may be justified by site-specific soil-structure interaction analyses. The results may be used to confirm the seismic design adequacy of the certified design using approved procedures and acceptance criteria.

Table 5.0: ABWR Site Parameters

Maximum Ground Water Level:
2 feet below grade

Maximum Flood (or Tsunami Level)[3]:
1 foot below grade

Precipitation (for Roof Design):
- Maximum rainfall rate: 19.4 in/hr[5]
- Maximum snow load: 50 lb/sq. ft.

Design Temperatures:
- Ambient
  1% Exceedance Values
  Maximum: 100°F dry bulb/77°F coincident wet bulb
  Minimum: -10°F
  0% Exceedance Values (Historical Limit)
  Maximum: 115°F dry bulb/82°F coincident wet bulb
  Minimum: -40°F
- Emergency Cooling Water Inlet: 95°F
- Condenser Cooling Water Inlet: ≤100°F

Extreme Wind: Basic Wind Speed:
110 mph[1]/130 mph[2]

Tornado[4]:
- Maximum tornado wind speed: 260 mph
- Translational velocity: 57 mph
- Radius: 453 ft
- Maximum atm ΔP: 1.46 psid
- Missile Spectra: Per ANSI/ANS-2.3

Soil Properties:
- Minimum Bearing Capacity (demand): 15ksf
- Minimum Shear Wave Velocity: 1000fps[6]
  None at plant site resulting from OBE and SSE.

Seismology:
- OBE Peak Ground Acceleration (PGA)
  0.10g[7][8]
- SSE PGA: 0.30g[9]
- SSE Response Spectra: per applicable [illegible]
- SSE Time History: Envelope SSE Response Spectra

(1) 50-year recurrence interval; value to be utilized for design of non-safety-related structures only.

(2) 100-year recurrence interval; value to be utilized for design of safety-related structures only

(3) Probable maximum flood level (PMF), as defined in ANSI/ANS-2.8, "Determining Design Basis Flooding at Power Reactor Sites."

(4) 1,000,000-year tornado recurrence interval, with associated parameters based on ANSI/ANS-2.3.

(5) Maximum value for 1 hour of 0.15g is employed to evaluate structural and component responses of the certified design.

(6) This is the minimum shear wave velocity at low storms after the soil property uncertainties have been applied.

(7) Free-field, at plat grade elevation.

(8) For conservatism, a value of 0.15g is employed to evaluate structural and component responses in Chapter 3.

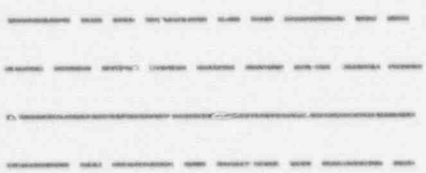
(9) Free-field, at plat grade elevation.

APPENDIX A LEGEND FOR FIGURES

For a number of the systems, presented in Section 2, simplified figures have been included to help facilitate the design description. The figures contain information that uses the following conventions:

Line classification:

	Figure Designation
ASME Code Class 1	1
ASME Code Class 2	2
ASME Code Class 3	3
Non-ASME Code	NC



Classification Boundaries:

The following is a self-explanatory example of how code class change are identified on the schematic diagrams:

1 | NC

Other line type:

Instrumentation:

Filter	F
Flow element	FE
Level detector	L
Moisture element	ME
Pressure element	P
Radiation element	RE
Restricting orifice	RO
Speed detector	S
Temperature element	T
Vibration detector	V
Water trap	TR

Equipment:

- Gate valve
- Globe valve
- Check valve
- Valve type not specified
- Relief valve
- Open cirucit breaker
- Closed circuit breaker
- Annunciator
  (H=high, L=low)
- Solenoid valve

Valves are shown on the figures in their normal postition.

Valve Operators:

Motor	M
Nitrogen	N
Air	A

APPENDIX B TIER 2 ITAAC CORRELATION MATRICES

In response to NRC requests, GE intends to prepare indexes which will identify the relationship between Tier 2 (the SSAR) entries and the Tier 1 ITAAC material. The intent of this index material is to provide a "road map" which will indicate which ITAAC entries are being used to verify key parameters defined in the SSAR. For example, it has been agreed there will be a matrix for SSAR Chapters 6 and 15 indicating which ITAAC will be used to verify the key safety system performance parameters assumed in the safety analyses described in these chapters. Other subjects that are candidates for such treatment are plant ATWS response and severe accident mitigation features.

It has yet to be decided how much of the Tier 2 SSAR material is to be included in this road map effort and how the information is to be documented. Options under consideration include:

(1) Keeping the indexes as an informal guide to assist NRC Staff in their review of the ITAAC development effort and ultimately in their development of the Tier 1 material required by the Rule.

(2) Formally integrating the indexes into the SSAR.

It is clear that this material is not intended to become part of Tier 1 since this would necessarily involve Tier 1 references to SSAR (Tier 2) sections and thus undesirable elevation of Tier 2 material to Tier 1 status.

Appendix B1 presents the proposed index for the Chapter 6 and 15 safety analyses discussed above.

Appendix B1 ABWR DESIGN CERTIFICATION ITAAC PREPARATION FOR SAFETY ANALYSIS VERIFICATION

Background

During recent GE/NRC meetings on ITAAC, the concept of safety analysis verification was discussed. The approach would be to use ITAAC entries as a mechanism for confirming that the as-built plant has attributes compatible with values used in important SSAR safety analyses. As an example, the drywell-to-wetwell venting area is an important input to the containment LOCA analyses. An entry in the set of containment system ITAAC would call for field confirmation that sufficient vent area had, in fact, been provided.

As a result of these discussions, GE agreed to identify which SSAR safety analysis assumptions should be selected for ITAAC treatment and to prepare an index indicating which system, generic or DAC, ITAAC should be used to accomplish verification of each individual safety analysis assumption. The purpose of this Appendix is to summarize the GE proposals on this subject.

Discussion

The GE ABWR SSAR contains a variety of plant safety evaluations covering the full spectrum of transient events, design basis accidents and conditions beyond the design bases (e.g., ATWS and severe accidents). The following table summarizes the most important SSAR safety analyses:

SSAR Section:	Safety Analyses:
Chapter 15	Plant transient analyses
Section 6.2.1	Containment LOCA performance
Section 6.3.1	Reactor core LOCA performance

The SSAR contains other analysis results in Chapter 6 and elsewhere; however, these analyses are viewed (by GE) as being of lesser importance than the major items identified above and are not currently being included in the proposed ITAAC-based safety analysis verification effort.

The SSAR contains extensive information on the input values of parameters used in the plant safety analyses. Only the most significant parameters will be subject to verification through ITAAC entries. Parameter selection will be made using criteria which reflect the tiered approach to design certification and the Tier 1 status of ITAAC. Table B1a summarizes the selection criteria.

Safety Analysis Verification

The safety analysis input parameters that will be verified through the ITAAC process:

Chapter 15, Transient Analysis

Section 6.2.1, Containment LOCA Performance

Section 6.3.1, Reactor Core LOCA Performance

Table B1b summarizes the SSAR safety analysis assumptions which will be verified by ITAAC and identifies the proposed set of system ITAAC which will include the entry for a particular assumption.

Table B.1.a: Criteria for Selecting Safety Analysis Parameters to be Confirmed by ITAAC Entries

A parameter will be selected for ITAAC treatment if it has the following characteristics:

Characteristic	Bases
The parameter has a primary influence on the safety analysis results such that small variations could possibly result in changes to analysis results of some safety significance.	Self-evident compatibility with the tiered approach to design certification. Example: Primary containment post-LOCA leakage rate of 0.5% per day.
The parameter is a measurable characteristic of the plant which can be verified prior to fuel loading.	As defined in the Part 52 regulations, the ITAAC process must be completed prior to fuel load. Example: Area of steam-venting flow path between drywell and wetwell.
The parameter is a plant design characteristic and not an operating condition.	By definition, the ITAAC process does not encompass plant operating conditions. (These items are covered by Technical Specifications.) Example: The assumed pre-LOCA reactor pressure conditions would not be a candidate for ITAAC treatment.

Intent

The following points summarize GE's understanding of the intent of the proposed safety analysis verification effort.

(1) The index of SSAR safety analysis assumptions and the list of ITAAC which will verify each particular assumption will be retained in Tier 2. It will serve as a "road map" for SSAR review to clarify the linkage to Tier 1 ITAAC. The latter will not include a comparable reference back to the Tier 2 SSAR material. This is because any such reference would elevate the SSAR material to Tier 1 status.

(2) The safety analysis verification process only summarizes and cross-correlates ITAAC entries which would have been selected anyway, using the existing criteria for ITAAC selection. In other words, preparing the safety analysis verification ITAAC index does not add to or substitute from the plant ITAAC material.

(3) Final disposition of the safety analysis verification table has yet to be decided. It may be incorporated into the body of the SSAR; where and how this will be accomplished has yet to be decided.

Table B.1.b: Safety Analysis Verification Using ITAAC

SSAR Entry	Parameter	Value (1)	Verifying ITAAC
6.2.1	Containment Functional Design		
6.2.1.1.4.1	Vacuum Breakers		
	Diameter (inches)	20	2.14.1Primary Containment System
	Quantity	8	2.14.1Primary Containment System
Table 6.2-2	Drywell		
	Volume (ft^3)	259,563	2.14.1Primary Containment System
	Leak Rate, Drywell and Wetwell (%/Day)	0.5	2.14.1Primary Containment System
	Wetwell		
	Volume (ft^3)	210,475	2.14.1Primary Containment System
	Minimum Suppression Pool Water Volume (ft^3)	126,427	2.14.1Primary Containment System
	Total Vent Area (ft^2)	125	2.14.1Primary Containment System
	Vent Centerline Submergence (Low Water Level), (ft):		
	Top Row	11.48	2.14.1Primary Containment System
	Middle Row	15.98	2.14.1Primary Containment System
	Bottom Row	20.48	2.14.1Primary Containment System
Table 6.2.2-a	RHR System		
	Pump Capacity (gpm/pump)	4200	2.4.1Residual Heat Removal System
	Heat Transfer Area (ft^2/unit)		2.4.1Residual Heat Removal System
	Heat Transfer Coefficient (Btu/sec-F)	195	2.4.1Residual Heat Removal System
	Service Water Flow (lbm/hr)	2.63×10^6	2.4.1Residual Heat Removal System
Table 6.2-2d	Secondary Containment		
	Free Volume (ft^3)	3.0×10^6	2.15.10Reactor Building
	Pressure (inch H_2O)	-0.25	2.15.10Reactor Building
	Leak Rate (%/day)	50	2.15.10Reactor Building

Table B.1.b: Safety Analysis Verification Using ITAAC (Continued)

SSAR Entry	Parameter	Value (1)	Verifying ITAAC
Table 6.3-1	Low Pressure Flooder System		
	Minimum Vessel Pressure to Initiate Flow (psid)	225	2.4.1Residual Heat Removal System
	Minimum Rated Flow (gpm/unit) at Vessel Pressure (psid)	4200 40	2.4.1Residual Heat Removal System
	Initiating Signals Low Water Level (ft above TAF)	<0.6	2.1.2Nuclear Boiler System
	Maximum Time from Signal to Pumps at Rated Speed (sec)	29	2.4.1Residual Heat Removal System
	Maximum Time from Low Pressure Permissive signal to Injeciton Valve Fully Open (sec)	36	2.4.1Residual Heat Removal System
	RCIC System		
	Minimum Vessel Pressure to Initiate Flow (psid)	1177	2.4.4Reactor Core Isolation Cooling
	Minimum Rated Flow (gpm/unit) at Vessel Pressure (psid)	800 1177-150	2.4.4Reactor Core Isolation Cooling
	Initiating Signals Low Water Level (ft above TAF)	<8.1	2.1.2Nuclear Boiler System
	Maximum Time from Signal to Injection Valve Fully Open (sec)	29	2.4.4Reactor Core Isolation Cooling
	HPCF System		
	Minimum Vessel Pressure to Initiate Flow (psid)	1177	2.4.2High Pressure Core Flooder System
	Minimum Rated Flow (gpm/unit) at Vessel Pressure (psid)	800-3200 1177-100	2.4.2High Pressure Core Flooder System
	Initiating Signals Low Water Level (ft above TAF)	<3.4	2.1.2Nuclear Boiler System
	Maximum Time from Signal to Injection Valve Full Open (sec)	36	2.4.2High Pressure Core Flooder System
	ADS		
	Minimum Flow Capacity (lbs/hr) at Vessel Pressure (psig)	6.4×10^6 1125	2.1.2Nuclear Boiler System
	Initiating Signals Low Water Level (ft above TAF)	<0.6	2.1.2Nuclear Boiler System
	Maximum Time from Signal to Valves Fully Open (sec)	<29	2.1.2Nuclear Boiler System
Table 6.3-4	LOCA Break Sizing		

Table B.1.b: Safety Analysis Verification Using ITAAC (Continued)

SSAR Entry	Parameter	Value (1)	Verifying ITAAC
	Steamline (ft^2)	1.06	2.1.1Reactor Pressure Vessel System
	Feedwater Line (ft^2)	0.903	2.1.1Reactor Pressure Vessel System
	RHR Shutdown Cooling Suction Line (ft^2)	0.852	2.1.1Reactor Pressure Vessel System
	RHR Injection Line (ft^2)	0.221	2.1.1Reactor Pressure Vessel System
	High Pressure Core Flooder (ft^2)	0.099	2.1.1Reactor Pressure Vessel System
	Bottom Head Drain Line (ft^2)	0.0218	2.1.1Reactor Pressure Vessel System
Table 6.3-9	Design Parameters for RHR System Components		
	Pump Flow Rate (gpm)	4200	2.4.1Residual Heat Removal
Table 15.0.1	Input Parameters and Initial Conditions for System Response Analysis Transient		
	Safety/Relief Valve Capacity at 80.5 kg/cm^2 (%NBR)	91.13	2.1.2Nuclear Boiler System
	Recirculation Pump Trip Inertia Time Constant (sec)	0.62	2.1.3Reactor Recirculation System
	Steamline Volume (m^3)	113.2	2.1.2Nuclear Boiler System
Table 15.0-6	FMCRD Scram Time		
	Rod Insertion Time (sec)	3.719	2.2.2Control Rod Drive System
15.2	Increase in Rx Pressure		
15.2.2.3.1	TCV Full Stroke Closure (sec)	0.15	2.10.8Turbine Control System
15.2.3.3.1	Turbine Stop Valve Full Stroke Closure (sec)	0.10	2.10.9Turbine Control System
15.2.4.3.1	MSIV Closure (sec)	3-5	2.1.2Nuclear Boiler System
15.2.5.3.1	Same as 15.2.3.3.1		
15.4	Reactivity and Power Distribution Anomalies		
15.4.1.2.3.2	FMCRD Withdrawal (mm/sec)	30	2.2.2Control Rod Drive System
15.8	ATWS Events		

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Table B.1.b: Safety Analysis Verification Using ITAAC (Continued)

SSAR Entry	Parameter	Value (1)	Verifying ITAAC
15.8.2	SLCS Capacity	100	2.2.4Standby Liquid Control System
Table 15E.3-1	Initial Operating Conditions		
	Suppression Pool Volume (m^3)	3580	2.14.1Primary Containment System
Table 15E.3-2	Equipment Performance Characteristics		
	Relief Valve Capacity (%NBR Steam Flow/No. Valves)	91.3/18	2.1.2Nuclear Boiler System
	RHR Pool Cooling Capacity (Kcal/sec-C)/(%NBR at 38•C)	265/1.57	2.4.1Residual Heat Removal System

Notes:
1. This table is a summary of data presented in the SSAR. Margins and/or ranges may be added when these values are incorporated into specific ITAAC entries.

Appendix B2 ABWR PRA Studies

The influence of PRA findings on the ABWR design is currently being documented and will be included in Chapter 19 of the ABWR SAR. This SAR entry will include identification of design features which play an important role in minimizing the risk of core damage. The SAR material also will include a listing of the Tier 1 ITAAC which will be used to verify that the as-built facility includes the important risk-reducing features.

Because of these SAR documentation plans, no discussion of this issue is included in this document.